Electric Reliability Council of Texas

Market Restructuring
Cost-Benefit Analysis

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List of Abbreviations

A/S	Ancillary Services
ADAM	Auction Day-Ahead Energy Market
APS	Allegheny Power Service
AREP	Affiliated Retail Energy Provider
BGE	Baltimore Gas & Electric
CB	Cost-Benefit
CBCG	Cost-Benefit Concept Group
CC	Combined-Cycle
COOP	Electric Cooperative
CR	Congestion Rent
CRE	Closely Related Element
CRR	Congestion Revenue Right
CSC	Commercially Significant Constraint
CT	Combustion Turbine
DA	Day-Ahead
DaRUC	Day-Ahead Reliability Unit Commitment
DFW	Dallas–Fort Worth
DPL	Dayton Power and Light
DSM	Demand-side management
EC	Electric Cooperative
EHDAM	Enhanced Hybrid Day-Ahead Market
EIA	Energy Impact Assessment
EMMS	Energy Management and Market System
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FTE	Full-Time Equivalent
FTR	Financial Transmission Right
HA	Hour-Ahead
HaRUC	Hour-Ahead Reliability Unit Commitment
IIA	Implementation Impact Assessment
IOU	Investor-Owned Utility
IPM	Independent Power Marketer
IPP	Independent Power Producer
IREP	Independent Retail Electric Provider
ISO	Independent System Operator
ISO-NE	ISO New England
IT	Information Technology
LaaR	Load Acting as Resource
LFC	Load Frequency Control
LMP	Locational Marginal Price; Locational Marginal Pricing
LSE	Load-Serving Entity
MCPE	Marginal Clearing Price of Energy
MOU	Municipally Owned Utility (Muni)
MSA	Metropolitan Service Area
Muni	Municipal Utility
NIMBY	Not In My Back Yard

NOIE	Non-Opt-In Entity
NPV	Net Present Value
NSA	Network Security Analysis
O&M	Operation and Maintenance
OMIA	Other Market Impact Assessment
OOM	Out-of-Merit Order
OOMC	Out-of-Merit Order Capacity
OOME	Out-of-Merit Order Energy
PCR	Pre-Assigned Transmission Congestion Right
PCRR	Pre-assigned Congestion Revenue Right
PIP	Protocol Improvement Process
PM	Program Management
PRR	Protocol Revision Request
PUCT	Public Utility Commission of Texas
QSE	Qualified Scheduling Entity
RAP	Remedial Action Plan
RCC	Replication Change Case
REP	Retail Energy Producer
RMR	Reliability Must Run
ROS	Reliability and Operations Subcommittee
RPRS	Replacement Reserve Service
RT	Real-Time
RTO	Regional Transmission Organization
RUC	Reliability Unit Commitment
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SE	State Estimator
SFT	Simultaneous Feasibility Test
TCR	Transmission Congestion Right
TDSP	Transmission and/or Distribution Service Provider
TNM	Texas Nodal Model
TNT	Texas Nodal Team
TTC	Total Transfer Capability
VOM	Variable Operation and Maintenance

Executive Summary

Background

Tabors Caramanis & Associates (TCA) and KEMA Consulting, Inc. (KEMA) were contracted by the Electric Reliability Council of Texas (ERCOT) to undertake an analysis of the probable costs and benefits of implementing a nodal market structure in ERCOT. This Cost-Benefit Study was ordered by the Public Utility Commission of Texas (PUCT) as part of PUC Substantive Rule 25.501 under PUCT project 26376. The Rule called for an in-depth study of the market structural options of a nodal design in the ERCOT control area, with direct assignment of local congestion, in comparison to maintaining the current "Base Case" market design. ERCOT market participants developed the nodal market design and the case options considered in the study.

ERCOT formed a Cost-Benefit Concept Group (CBCG), representing ERCOT stakeholders,[1] to guide the cost-benefit effort. The CBCG selected a study methodology that included a detailed modeling of the transmission system and consideration of benefit and cost impacts that were not susceptible to modeling. The stakeholder group conducted a competitive process for the selection of a consultant to conduct the Cost-Benefit Study beginning in January of 2004, worked with TCA and KEMA to develop a detailed scope of work, and contracted with TCA/KEMA to perform work under this scope. TCA/KEMA and the CBCG jointly developed the assumptions to be used in the analyses. The study was conducted throughout 2004 under the direction of the CBCG. The CBCG reviewed critical assumptions and provided feedback throughout the study process. ERCOT staff provided input on matters related to the existing market design, existing systems, and impacts experienced with the current market design. Drafts of the various elements of the study were prepared beginning in the summer of 2004 for stakeholder feedback. This is the final, comprehensive Cost-Benefit report.

While most Cost-Benefit studies conducted in the wholesale electric industry have focused on assessing the benefits of moving to a more open market design or have considered the implementation of a Regional Transmission Operator (RTO), this ERCOT Cost-Benefit study focused on two alternative market design choices: a zonal market design and a nodal market design. The zonal Base Case reflected ERCOT's current mode of operation, in which costs to move between (or manage congestion associated with) the boundaries (or Commercially Significant Constraints—CSCs) of the major electric transmission system (zones) are charged directly to users and in which the cost of managing congestion within each zone is spread to all loads (socialized). In this case, all generating resources within a zone are treated as if their output has an equal effect, relative to other generators in their zone, on flows on the zonal boundaries, the CSCs. (In transmission-system terms, each generator within a zone has an equal "shift factor" with respect to each CSC.) In this zonal model, because each generator is treated in this equivalent, average manner, ERCOT operators must implement operational limits on the CSCs to ensure that actual CSC line flows do not overload the system when generators' output results in flows consistent with the actual (rather than average) system impacts (shift factors).

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[1] Note that the CBCG was open to all stakeholders, and participation resembled to some extent the make up of the Segment classes called out in the study. The CBCG did include a Liaison Team to provide a specific set of individuals to interface with TCA and KEMA. The Liaison Team included members from the Independent Power Producer/Marketer segment, the PUCT, ERCOT, and the Municipal segment. Beyond the structure provided by the Liaison Team, participation in the CBCG was through self-selection.

In the nodal Change Case, each element of the transmission system is treated explicitly, each generator's actual impact on each transmission element is considered, and users are charged the marginal cost of their own total impact on the system. That is, generators and loads pay the marginal cost of congestion on all constraints, including local (or in-zone) constraints. Each load and generating point may therefore see a different locational marginal price, or LMP. The Texas Nodal Model (TNM) design calls for the averaging of prices for load nodes within each of four zones: North (including the Northeast portion), South, East, and West.

The TNM design also calls for several other market design changes relative to the present ERCOT market rules; one significant change is the bidding and deployment of resources individually, rather than as a "portfolio."

The overall purpose of the study, in the view of the TCA/KEMA team, was to provide support for further dialog and decision-making associated with the nodal market design. That being the case, the costs and benefits of the nodal market design are therefore not the only important output of the study: perhaps more important are the insights provided by the study into the behavior of the ERCOT physical and market system. In particular, the study identified areas in which impacts appear sensitive to market structural choices and other areas in which impacts are not sensitive. Further, the study provides a structure (study assumptions, methods, and findings) that can support continued discussion and learning about the potential impacts of various elements of the market design elements.

Methodology

The study consisted of four elements:

a) **Energy Impact Assessment (EIA)**—quantified impacts to the energy market, system dispatch, energy prices, and resulting production system costs. TCA conducted the EIA.
b) **Backcast**—quantified optimized generation dispatch results for the ERCOT system for 2003 for comparison with those actually experienced. TCA conducted the Backcast.
c) **Implementation Impact Assessment (IIA)**—provided quantitative and qualitative treatment of implementation startup costs, ongoing costs, and other transition-related impacts for ERCOT and its market participants. KEMA conducted the IIA.
d) **Other Market Impact Assessment (OMIA)**—provided qualitative treatment of a variety of other measures of impact of market designs not captured directly in the EIA. TCA conducted the OMIA.

The EIA, IIA, and OMIA considered a ten-year horizon (2005–2014). TCA and KEMA coordinated their efforts to ensure that case definitions and assumption sets were consistent from one study element to another. Each study element addressed impacts to regions, if applicable, and to the various market segments:

Regions	Market Segments
North Zone	Investor-Owned Utilities
South Zone	Municipal Utilities
West Zone	Electric Cooperatives
Houston Zone	Independent Power Generators or Producers
	Independent Power Marketers
	Independent Retail Electric Providers
	Affiliated Retail Electric Providers

Four cases were considered in some, but not all, elements of the study. The Base Case reflected the existing ERCOT market design as of the spring of 2004. The Change Case was defined in TNM white papers approved by the ERCOT Board of Directors in the Spring of 2004. Two alternative change cases were also defined: (1) the Replication Change Case, which was based on the market design of ISO New England (ISO-NE) but included many, but not all, of the TNM design provisions, and (2) the Nodal Light Change Case, which called for a simplified representation of the TNM, reflecting pricing only at resource nodes.

The Energy Impact Assessment, a simulation analysis conducted by TCA, examined the engineering economics of operation of the ERCOT, for the zonal Base Case and the TNM Change Case for each year of the ten-year study horizon. (Differences between the TNM Change Case and the two alternative change cases were too subtle to be measured in the EIA.)

a) The study used the GE-MAPS least-cost dispatch simulation tool to analyze energy flows, energy pricing, and market dynamics such as differences in dispatch and in siting price signals between the two cases. The simulation quantified economic impacts associated with two primary drivers:
   - More efficient utilization of generating resources under nodal market operations than in zonal operations (which use average shift factors and lower operation limits for the Commercially Significant Constraints).
   - Alternative siting scenarios under zonal and nodal market designs.

   The analysis examined the cost to serve system load and the marginal price of energy to determine the impact to the energy value loads pay and the revenues generators receive. GE-MAPS simulated the hour-by-hour physical and economic behavior of the ERCOT power grid for both cases.[2] The analysis determined, for each hour, the spot market price at each major transmission bus or zone (in the case of the zonal market). Results were determined for the ERCOT region as a whole, for various market participant segments, and for each major region within ERCOT.

b) **The Backcast** was not a comparison of the Base Case with the Nodal Case. Rather, it compared simulated zonal case least-cost generation dispatch results for 2003 (based on historical fuel prices, actual loads, actual generation outages, and hourly schedules for hydro and wind facilities) with ERCOT's actual 2003 dispatch results. The purpose of the

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[2] GE-MAPS, a product of the General Electric Corporation, is a Security Constrained Dispatch Model. It calculates the optimal (least cost) dispatch of all generators within the studied system subject to transmission constraints and subject to the possibility of transmission system operating outages, hence the description, "Security Constrained Dispatch."

Backcast was to provide a comparison that parties believed may be useful in examining the difference between efficient/optimal dispatch and the actual dispatch in the ERCOT system.

c) **The Implementation Impact Assessment** (IIA) was intended to estimate the implementation costs to change from the Base Case to each of the three change cases, in enough detail to allow the Commission and stakeholders to modify or delete specific items or categories of expenses as required by PUC Substantive Rule 25.501.

The implementation costs include capital costs and incremental operations and maintenance costs. Significant cost drivers were clearly identified.

KEMA identified the changes to major activities and business processes implied by each of the change case designs, surveyed market participants, interviewed ERCOT staff to capture the state of existing systems, and determined impacts to people, processes, and technologies. From these impacts KEMA categorized the nature of the changes and estimated resulting capital and operating cost impacts. KEMA further defined costs based on market segment types.

d) **The Other Market Impact Assessment** (OMIA) was intended to make a qualitative assessment, by market segment and for all three change cases, of the impacts of aspects of the market design changes not analyzed quantitatively in the other elements of the study. For the purposes of the OMIA, seven categories of Significant Design Changes and nine categories of Commercial Impacts were identified:

Significant Design Changes

Real-Time Market: Nodal Deployment
Real-Time Market: Nodal Settlement
Congestion Revenue Rights
Pre-assigned Congestion Revenue Rights
Reliability Unit Commitment
Modeling Details and Requirements
Outage Scheduling

Commercial Impacts

Competitive Markets
Discriminatory Environment
Efficiency of Production
Efficient Resource Expansion
Efficient Grid Expansion
Grid Reliability
Market Power
Ability to Conduct Business
Costs and Administrative Burdens

In the OMIA, TCA considered each of the Significant Design Changes in each applicable Commercial Impact category, using assessments based on a variety of information and factors. TCA reviewed third-party sources to identify the impacts of various design elements in several other electricity markets and collected information directly from staff at ERCOT, PJM, and ISO-NE. TCA also relied on its own consultant expertise and on feedback provided by ERCOT stakeholders.

Findings

The year-by-year results of the EIA can be conveniently divided into three periods:

- 2005–2008, during which the resource mix is unchanged, so that the results are limited to impacts of operational efficiency;
- 2009–2011, during which the benefits of the nodal Change Case tend to grow each year because of more efficient siting of new generation;
- 2012–2014, during which the transmission system assumptions used (i.e., a lack of transmission system expansion) begin to influence the behavior of the results.

Grouping the EIA results in this way makes it easier to appreciate the impact of the two main drivers of the energy impacts, operational efficiencies and long-term siting decisions.

The nodal Change Case is measured to produce average annual benefits of $76 million per year (corresponding to a ten-year net present value, or NPV, of $586 million) in reduced generation costs. For the nodal Change Case, the study measured a significant shift in value from the ERCOT market's generator segment to its load segments.

Year	Generation Cost Reduction of TNM Change Case Relative to Base Case		
	($M)	**($/MWh)**	**(%)**
2005	27.3	0.08	0.19
2006	58.6	0.17	0.42
2007	81.6	0.23	0.60
2008	99.5	0.27	0.73
2009	109.4	0.29	0.84
2010	46.4	0.12	0.36
2011	152.0	0.39	1.17
2012	147.8	0.37	1.07
2013	68.1	0.17	0.47
2014	(28.1)	(0.07)	-0.19
Total	762.7	—	—
Average	76.3	0.20	—
NPV	586.6	—	—

Over the study horizon, generators' net revenues are $781 million lower on average (or a ten-year NPV of –$6 billion[3]) under the nodal market design, and loads' net cost is $823 million less per year on average (a ten-year NPV of $6.3 billion). Although these impacts seem significant, they are not large fractions of the total energy system costs. For example, average system cost savings of $76 million per year represent less than 1% of the total system cost.

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[3] In this Executive Summary, increased costs and decreased revenues are negative impacts as indicated by a minus sign or parentheses, and decreased costs and increased revenues are positive impacts. A positive NPV represents a net overall gain, and a negative NPV represents a net overall loss.

The Independent Power Producer (IPP) segment is adversely affected by the nodal market, given that energy prices and revenues decline and that the IPP portfolios (by definition) do not include any load. IPPs suffer an average annual impact of –$304 million.

Year	IPP Total Margin	
	($M)	($/MWh)
2005	(427)	(3.41)
2006	(387)	(3.01)
2007	(398)	(2.94)
2008	(404)	(2.86)
2009	(183)	(1.28)
2010	(125)	(0.91)
2011	(108)	(0.80)
2012	(104)	(0.79)
2013	(104)	(0.82)
2014	(803)	(6.88)
Total	(3,044)	—
Average	(304)	(2.37)
NPV	(2,378)	—

The energy benefits measured in the EIA are positive for all other all market segments, primarily because of the substantial savings in the cost to serve load.

From a load serving entity's perspective, the benefits accrue to all regions, but less so to the South Zone. This is because the nodal market operations provide more efficient congestion management, especially with respect to the constrained transmission paths in and around Houston. As a result, more energy flows from the South to Houston, and prices between the South and Houston Zones equalize somewhat. This increases the cost of energy to buyers in the South Zone. As a result, the cost to serve load in the South Zone under the nodal Change Case does not become lower than under the Base (zonal) case until after 2010.

Implementation costs determined in the IIA result in a total market impact of –$108 million to –$157 million due to the increased capital and operating costs of the nodal market systems and support staff. Most of this cost will be borne directly by ERCOT, which is likely to pass the cost on to market participants. Implementation impacts to each market participant segment range from approximately –$9 million to –$15 million NPV for sophisticated market participants such as Investor-Owned Utilities and IPPs to –$1.3 to –$3 million NPV for small Retail Energy Providers. The impacts are based a range of estimated costs, as indicated by the TNT (high) and TNT (Low) results in the following table of overall NPV cost impacts by market segment.

Market Segment	TNT (high) ($K)	TNT (low) ($K)
ERCOT	76,305	59,764
Investor-Owned Utilities	16,295	10,371
Municipally Owned Utilities	13,782	8,533
Electric Cooperatives	13,577	8,584
Independent Power Producers	16,206	9,571
Independent Power Marketers	11,300	6,607
Independent Retail Electric Providers	3,159	1,446
No Segment Designation	6,132	2,808
Total	156,755	107,684

Significant **Other Market Impacts** found in the OMIA include an increase in complexity with the shift to the nodal market design. This is especially prevalent during the first few years of nodal market operations, and it disproportionately impacts small participants and participants whose business is limited to the ERCOT region. Other impacts are expected to include a risk shift, from today's load serving entities to transmission rights holders under the nodal model, resulting from the derating of transmission rights and from the direct assignment of the marginal value of local congestion. The application of new algorithms and the implementation of other systems with the nodal market design create other risks of unexpected market outcomes. Qualitative benefits include ERCOT's improved ability to manage the system with unit-specific bids rather than portfolio bids, and the resulting increased system efficiency and increased transparency of prices at specific locations.

The two alternative change cases did not result in significantly lower implementation costs. Qualitatively, the Replication Change Case offers a reduction in risk given the use of algorithms and systems already in use in ISO-NE. The Nodal Light case has some drawbacks relative to the TNM, given its simplified system representation.

In the **Backcast analysis**, the pattern of simulated results and actual system results were substantially similar, but there were some significant differences. In the simulated case, combined-cycle resources generated more than was actually the case, and steam-turbine gas plants generated less. These differences, when priced, result in a difference of approximately $1 billion between simulated and actual system cost, with simulated being less than actual. This difference can be attributed to some combination of two drivers, whose relative impacts could not be isolated given the nature of the analysis: (1) simplifications in the comparison process and (2) actual differences in efficiencies between the market behavior and the simulated optimal outcome.

CONCLUSION

Although the three major elements of the study cannot be combined to produce a single conclusion with respect to the quantitative merits of implementing a nodal market in ERCOT, the potential savings found in the Energy Impact Assessment, relative to the Implementation costs found in the Implementation Impact Assessment, suggest that the benefits of the TNM could outweigh the costs for the ERCOT region as a whole. The report identifies some study assumptions that may have resulted in an overestimate of the energy impacts, including for example siting assumptions based almost entirely on energy economics, but this is not likely to materially change the preponderance of savings over costs.

The qualitative impacts are both positive and negative. Although it seems unlikely that the qualitative impacts could outweigh the quantitative impacts, it should be recognized that many of these other impacts tend to adversely affect smaller and regional market participants disproportionately.

1 Organizational Outline

This report is organized as follows.

- Section 2 provides background and context for this Cost-Benefit study.
- Section 3 provides the Energy Impact Assessment (EIA), the assessment of ERCOT market design alternative impacts on energy flows, market dynamics and energy pricing through the use of the quantitative generation and transmission simulation model, GE-MAPS. Using the GE-MAPS modeling system, this analysis produced quantitative analytic results based on the economic and physical operation of the regional power system. The Energy Impact Study Approach, detailed assumptions, and Base Case and sensitivity results are presented in Section 3.
- Section 4 contains the Backcast analysis of simulated zonal 2003 dispatch results relative to actual 2003 dispatch.
- Section 5 presents KEMA's study of the costs and other impacts of implementing the alternative market design cases. This is presented in Section 5 as the Implementation Impact Assessment (IIA).
- Section 6 contains TCA's qualitative analysis of other market impacts of the market design alternatives, the Other Market Impact Assessment (OMIA).
- Section 7 organizes the EIA, IIA, and OMIA results by region and by segment and provides further details regarding the impacts on particular geographic regions and market segments.

In order to provide a manageable printed document, detailed (and voluminous) output data associated with the EIA and the IIA are not included here. These data are available for electronic downloading.[4]

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[4] Available from ERCOT at <http://www.ercot.com/TNT/?func=documents>.

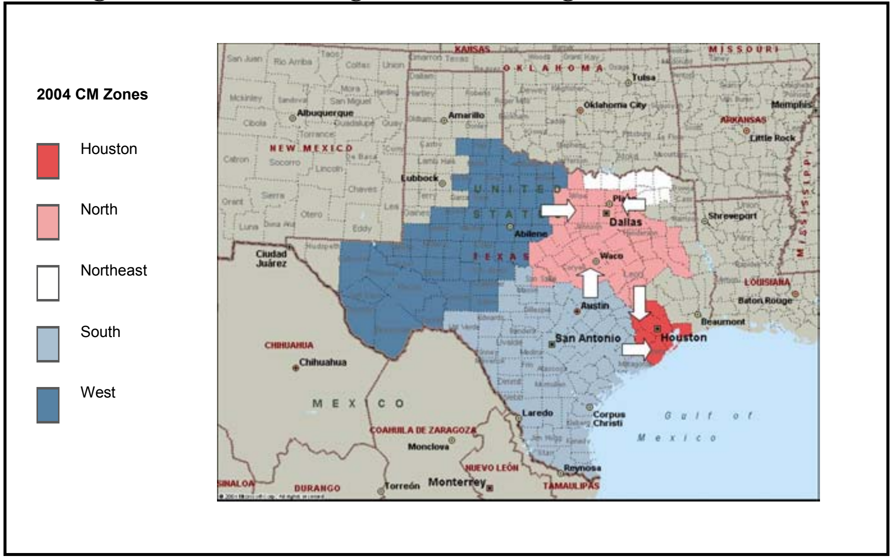
2 Background

This Cost-Benefit Study was ordered by the Public Utility Commission of Texas (PUCT) as part of PUC Substantive Rule 25.501 under the PUCT project 26376. The rule requires the Electric Reliability Council of Texas (ERCOT) to modify its existing wholesale market structure to implement direct assignment of local congestion. This "Texas Nodal" rule additionally requires resource-specific bidding for energy and ancillary services, implementation of a voluntary day-ahead market, nodal prices for resources, and zonal prices for loads.

The rule also called for an in-depth study of the market structural options of a nodal design in the ERCOT control area in comparison to maintaining the current, or "Base Case" market design. Prior to the execution of the Cost-Benefit study, and continuing throughout the study, ERCOT market participants developed the nodal market design and the case options considered in the study.[5]

ERCOT is an independent, not-for-profit organization responsible for the reliable transmission of electricity across Texas' interconnected 37,000-mile power grid. ERCOT is also charged with overseeing the transactions related to the January 1, 2002, restructuring of the electric industry—including the development and effective operation of the competitive retail market in its region. ERCOT is accountable for working with stakeholders to develop a nodal market design as a replacement to its existing zonal market design in accordance with PUC Substantive Rule 25.501. Figure 2-1 shows the ERCOT region and the existing Zonal Structure.

Figure 2-1 ERCOT Region with Existing Zonal Structure


2004 CM Zones
Houston
North
Northeast
South
West
KANSAS
MISSOURI
OKLAHOMA
Tulsa
Oklahoma City
Memphis
ARKANSAS
Little Rock
Albuquerque
Amarillo
NEW MEXICO
Lubbock
UNITED STATES
TEXAS
Abilene
Dallas
Shreveport
Waco
MISSISSIPPI
Ciudad Juárez
LOUISIANA
Baton Rouge
Austin
Beaumont
San Antonio
Houston
CHIHUAHUA
Chihuahua
MEXICO
Laredo
Corpus Christi
Gulf of Mexico
COAHUILA DE ZARAGOZA
Monclova
NUEVO LEÓN
Reynosa
SINALOA
DURANGO
Torreón
Monterrey
TAMAULIPAS

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[5] In this report, the Texas Nodal Market ("TNM") generally refers to the design that the ERCOT stakeholder groups have developed. In parts of this Cost-Benefit analysis, especially in the Energy Impact Analysis, the set of market design assumptions used to represent this TNM case is referred to as the "Change Case," and strictly speaking the Change Case may not fully represent all aspects of the TNM as they are defined. Similarly, the existing zonal market design was used in comparison, as defined by the existing set of protocols. Again, especially with respect to the Energy Impact Analysis, this case is represented as a set of assumptions referred to as the "Base Case." In many cases "TNM" and "Change Case" are used interchangeably in this document as are the (current) "zonal case" and "Base Case."

ERCOT's members include retail consumers, investor- and municipally owned electric utilities, rural electric cooperatives, river authorities, independent power producers, competitive retailers, and power marketers.

ERCOT's Cost-Benefit Concept Group (CBCG) selected a study methodology that included a detailed modeling of the transmission system and that looked into other benefit and cost impacts of ERCOT in more depth. The stakeholder group conducted a competitive selection process beginning in January of 2004, worked with TCA and KEMA to develop a detailed scope of work, and contracted with TCA/KEMA to perform work under this scope.[6] Following those initial steps, TCA and the CBCG worked closely to develop the assumptions to be used in the analyses.

TCA and KEMA presented status updates and detailed approaches throughout the study period.[7] TCA and the study group reviewed the results and refined the assumptions. Given the complexities of the study, it was necessary to "freeze" the definition of the cases, and the CBCG accordingly identified for TCA/KEMA those sets of documents that defined the two cases for analysis. Essentially the cases were based on the nodal market design as it was defined in the spring of 2004 and also on those anticipated Base Case changes recognized by the ERCOT Protocol Review Process and approved by the ERCOT Board as of March 31, 2004. This report presents the results of the ultimate modeling activities and the complete results of the other Cost-Benefit elements.

2.1 Cost-Benefit Studies in Electric Industry Restructuring

Starting in the 1970s and continuing through the 1990s, a number of studies have attempted the measurement of a variety of benefits from increased competition and the restructuring of the U.S. electric utility industry.[8]

On December 17, 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000. FERC next proposed a set of Regional Transmission Organizations (RTOs), and in 2001 it commissioned a cost-benefit study of RTOs and their markets.[9] This was the first of a wave of specific studies on the benefits and costs of RTOs.[10] This section briefly surveys five of these studies[11] (references for these studies are listed in Appendix 2-1:

1. The ICF FERC Study
2. The PJM Northeast RTO Study
3. The TCA RTO West Study

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[6] Posted at <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=63&b=>

[7] Ibid.

[8] See the recent summary by Michaels (September 2004).

[9] ICF FERC Study.

[10] The CRA SEARUC Study, p. 97, has an appendix providing a detailed comparison of six different RTO studies.

[11] In addition to these, two additional studies are under way: one focusing on impacts of stages of RTO Implementation in the WestConnect region, and the measurement of benefits of SPP RTO as well as the measurement of potential benefits of implementing an Energy Imbalance market in that region.

4. The CRA SEARUC Study
5. The CAEM PJM Study

These studies differ in a number of key attributes, addressing different policy questions and comparing market restructuring at various stages of integration. Central to the comparison of these studies is the question being addressed. The ICF FERC study addresses the national policy question "Should we encourage RTO development?" Two other studies, the TCA RTO West and CRA SEARUC studies, address the forward-looking benefits of initial new RTO formation. The PJM NERTO Study addresses the integration of existing operational Independent System Operators (ISOs) and RTOs. The CAEM Study is a historical retrospective. These studies are summarized in Table 2-1.

None of these studies addresses the core issue before ERCOT: What are the benefits of a shift in tariff structure from zonal to nodal pricing in an existing RTO? A predominant feature of the past Cost-Benefit studies is the comparison of costs and benefits of moving from pre-competition or pre-RTO structures to RTO structures or to market structures with more competition.

The ERCOT Cost-Benefit Study, on the other hand, focuses on two alternative RTO/ISO designs: a decentralized zonal market design (the existing market structure) and a centralized nodal market design (the contemplated market structure). Although the types of benefits measured are similar, the primary drivers are different, including measuring the incremental production efficiency of the alternative market designs and the incremental cost impacts of transitioning to, and operating, the alternative market design.

Table 2-1 Comparison of Select Industry Cost-Benefit Studies

	ICF FERC Study	PJM NERTO Study	TCA RTO West Study	CRA SEARUC Study	CAEM PJM Study
Market Focus	Nationwide	Integration of NE RTOs	RTO West (and impacts on rest of WSCC)	Formation of multiple sub-region RTOs	Historical examination of PJM benefits
Key Issue Addressed	Economic benefits of FERC RTO Policy change	Economic benefits of ISO and RTO integration	Economic benefits of RTO formation	Economic benefits of RTO formation and coordination	Benefits of PJM RTO in historical context
Benefits	Improvements in transmission system operations, inter-regional trade, congestion management, reliability and coordination; improved performance of energy markets, including greater incentives for efficient generator performance; and enhanced potential for demand response.	Improvements in production cost	Improvements in dispatch with reduction in transmission rate “pancaking”	Improvements in production cost, reflecting implications of transmission funding/ tariff alternatives	Benefits in wholesale, retail, capacity, and demand response markets, based on assumptions that restructuring dominated the price changes in the period and thus illustrate the benefits
Costs	RTO formation cost	Cost of RTO/ISO integration	RTO formation costs	RTO formation costs	—
Net Benefit Treatment	No separation of producer surplus gains/losses from consumer surplus impact	Total production cost less formation/integration cost	Gains/losses in producer and consumer surpluses	Native load benefits	Change in consumer surplus; rejects consideration of producer surplus impact
Sub-regional impacts	—	Included	Included	Included	PJM and adjacent states

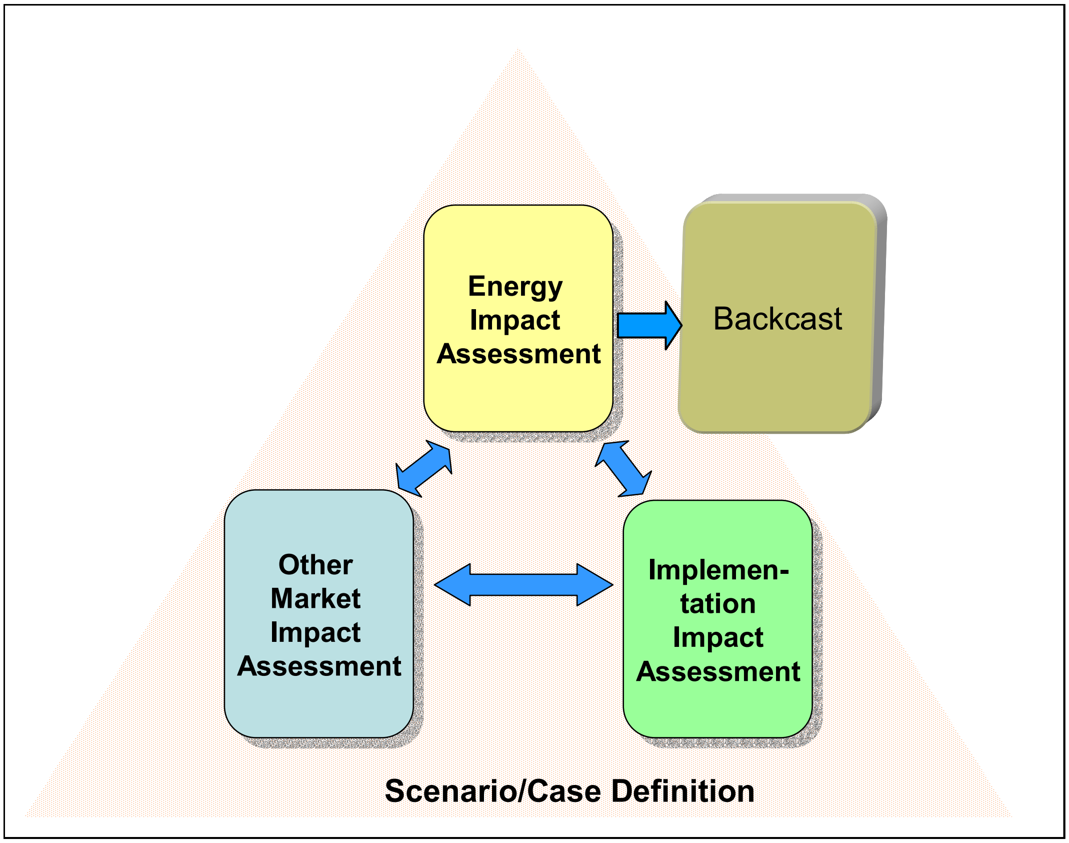
	ICF FERC Study	PJM NERTO Study	TCA RTO West Study	SEARUC Study	CAEM PJM Study
Long-run benefits	Estimates of improved generator efficiency and demand response	—	—	—	—
Time Horizon	Forecast 2002–2021	Two years forecast, 2005 and 2010	Single-year forecast, 2004	Forecast 2004–2013	Historical analysis 1997–2002
Primary methodology	Nationwide LP simulation of power system, fuel markets, and environmental limitations	MAPS generation and transmission modeling	MAPS generation and transmission modeling	MAPS generation and transmission modeling	Ad hoc historical analysis
Treatment of constraints reduced by shift in policy	Mostly technological change	—	Specific treatment of institutional changes and impact on dispatch	Specific treatment of institutional changes and transmission tariff development	—
Key Conclusions	Substantial but uncertain benefits from RTO development	Combination of 3 NE RTOs has no net benefit	Modest benefits in core RTO region	Benefits uncertain, negative in some sub-regions	—
Release date	February 2002	January 2002	March 2002	November 2002	Sept/Oct 2003

2.2 Cost-Benefit Study General Approach

This section introduces the general bodies of work constituting the Cost-Benefit study.

The ERCOT Cost-Benefit Study consisted of four major elements, all based on a single set of defined cases. The four study elements are shown in Figure 2-2.

Figure 2-2 Study Elements


Energy Impact Assessment
Backcast
Other Market Impact Assessment
Implemen-tation Impact Assessment
Scenario/Case Definition

Briefly, the study elements are as follows.

e) **Energy Impact Assessment**—quantifies impacts to the energy market, system dispatch, energy prices, and resulting production system costs.

f) **Backcast**—quantifies the dispatch results of the GE-MAPS zonal model relative to those experienced in the ERCOT system in 2003.

g) **Implementation Impact Assessment**—provides quantitative and qualitative treatment of implementation startup costs, ongoing costs, and other transition-related impacts for ERCOT and its market participants.

h) **Other Market Impact Assessment**—provides qualitative treatment of a variety of other measures of impact of market designs not captured directly in the EIA.

A description of each of these areas follows.

1. Energy Impact Assessment

The EIA addressed the expected impacts on the ERCOT energy markets due to the fundamental differences between the zonal and nodal market designs. The EIA included the production cost modeling, measuring the impacts on the dispatch of the system, resulting energy prices, and energy costs to users.

The system costs associated with each market design alternative served as one metric for comparison. TCA's approach used payments made by loads to purchase energy, and generator payments and costs, as measures of benefits (or changes in total welfare) of the Base and Change (Nodal) Cases. While we report "congestion costs," these costs are just one aspect of the system, and minimizing congestion costs alone will not necessarily maximize the benefits of the ERCOT market.

In this section we describe how the zonal and nodal market differences are treated in the EIA.

Zonal and Nodal Analysis

This section lays out how TCA represented the Zonal and Nodal Cases in the EIA, including a discussion of the modeling of the Base Case and the Change Case.[12]

Power system modeling is generally either zonal or nodal in nature. While some tools such as GE-MAPS perform detailed nodal dispatches, other modeling tools were designed more as transportation models under the assumption that regions could be represented as zones. Both nodal and zonal approaches must be used for ERCOT's study.[13] Further, even the existing (Base Case) zonal market design requires the resolution of local congestion with locational redispatch. In order to properly capture the impacts of different design structures, TCA used a hybrid zonal/nodal approach.

For the zonal representation TCA performed two-step simulations (one step corresponding to the zonal unit deployment and another corresponding to resolving local congestion and further zonal rebalancing). These simulations are complemented with the specially designed and implemented post-processing logic to reflect price formation on the zonal basis and compensation of generating units resolving local congestion through Out-of-Merit Order

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[12] Note that the Cost-Benefit study includes a total of three change cases: the Texas Nodal Market case (Change Case), the Replication Change Case (RCC), and the Nodal Light case. However, when evaluated TCA and the Cost-Benefit Concept Group determined that the two alternative changes were not different in the areas that were represented in the EIA. Therefore, in this EIA analysis all three change cases are treated as one simulation. The alternate change case differences are addressed in the IIA and the OMIA.

[13] It is important to note that the ERCOT Zonal system is not a "transportation model" system but a flowgate zonal system.

Energy (OOME) payments. This representation also reflected recent improvements in ERCOT's operating system. A pure nodal run was then used for the Locational Marginal Price (LMP)-based solution for the Change Case. Metrics including the costs of generation, generation revenues, and costs to serve load were produced in each case. For the Base Case, the cost of inter-zonal congestion management and the uplifted OOME costs were calculated. For the Change Case, congestion rents based on LMPs were generated.

2. Backcast

This Section presents TCA's analysis comparing simulated dispatch results with actual ERCOT resulting system dispatch for the year 2003. The work compared a simulated 2003 year system dispatch costs with the costs associated with the actual dispatch.

This analysis was performed to compare the theoretically-efficient outcome of a simulation with the actual market dispatch to date. The Backcast was not intended to fulfill any benchmarking role nor to test the performance of the simulations.

3. Implementation-Related Costs and Impact Assessment

The purpose of the Implementation Impact Assessment (IIA) portion of the study, performed by KEMA, was to develop detailed cost estimates of the implementation costs to change from the existing ERCOT market design (the Base Case) to each of the nodal market designs defined in three change cases. A summary of the change cases is described below.

The cost estimates provided are at a level of detail that would allow the Commission and stakeholders the necessary information to modify or delete specific items or categories of expenses as required by P.U.C. SUBST. R. 25.501.

The cost estimates provided include both the capital costs and incremental O&M only, resulting from the change in each market design. Items that are significant cost drivers are clearly identified, as are the assumptions that drive the estimates.

4. Other Market Impact Assessment

This section describes another body of work TCA performed for the Cost-Benefit Study, the Other Market Impact Assessment (OMIA). It is constructive to first note that the production cost model is not well suited to assess a significant number of impacts potentially resulting from a change in market structures. It is important for readers to distinguish between attributes that are amenable to being represented in a production cost model and those that better lend themselves to treatment outside of such a model. The OMIA addressed impacts of the market design changes other than those found in the EIA and those implementation-related impacts.

The OMIA is qualitative. However, the analysis is nonetheless critical and included a comparable level of rigor even given the qualitative nature of the work.

Essentially the OMIA is a matrix of evaluations in which various market attributes are compared with various impact measures or metrics. TCA consultants examined, on one hand, a number of characteristics of the markets being assessed (e.g., the real-time energy pricing policies or transmission right product design) against, on the other hand, a variety of metrics (such as volatility, risk, and competition).

As part of the OMIA, TCA assessed those characteristics of the market design alternatives as they influence metrics such as those listed.

Outline: Balance of the Report

The following sections present in detail these areas of the Cost-Benefit study, their approach, and the results:

- Section 3—Energy Impact Assessment
- Section 4—Backcast
- Section 5—Implementation Impact Assessment
- Section 6—Other Market Impact Assessment
- Section 7—Combined Segment Analyses

3 Energy Impact Assessment: GE-MAPS Study

TCA conducted a quantitative EIA of the ERCOT system under two scenarios: a status quo case ("Base Case") in which ERCOT continues to settle based on a zonal market design and a case in which ERCOT implements a nodal market design ("Change Case"). The EIA used the GE-MAPS model[14] and incorporated the operating procedures and operational and physical transmission constraints currently used (Base Case) or proposed (Change Case) for ERCOT. The analysis is intended to provide insight into the theoretical economic operation of the ERCOT markets under both scenarios.

The results of the analysis are included. These results are based on model representations and input assumptions developed through extensive discussions with ERCOT operations, planning, and data management staff.[15] The market design for the Base Case was defined based on the current protocols plus the protocol revisions approved by the Board as of March 31, 2004. The design for the Change case was based on the white papers approved by March 31, 2004 and did not include changes to the market design considered after that point in time. The final assumptions were ones that the ERCOT CBCG considered as reasonably expected conditions for the years 2005 through 2014 (including the current ERCOT proposals on the nodal market design, fixed hydro schedules, and economically efficient markets with marginal cost bidding). Most realistically, the impacts fall within a range, and these results show the expected value of the energy impacts given the modeling assumptions.

3.1 Potential Impacts of a Nodal Market Design

The central purpose of this Cost-Benefit study is to provide an unbiased discussion of possible costs and benefits and to quantify them to the extent possible.

There are several possible energy impacts of a shift to a nodal market design[16] including:

- Reduction in local congestion costs
- More efficient and transparent dispatch of resources
- Improved siting of new resources

A movement to a nodal market will likely have impacts on energy market prices. The improved efficiency of a nodal market provides downward impacts on prices. Whereas, all else equal, pricing all intrazonal constraints on a marginal basis provides upward pressure on locational prices.

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[14] GE-MAPS is Multi-Area Production Simulation software developed by General Electric Power Systems and proprietary to GE.

[15] TCA worked with Operations staff to represent the ERCOT zonal market in GE-MAPS in as robust a fashion as reasonably achievable. ERCOT planning staff reviewed TCA's generation database, the transmission constraint development methodology and results, and the Backcast Actual data. TCA worked with ERCOT data management staff to develop robust methods for performing the segment analysis.

[16] The three impacts given here, for example, are listed in the PUCT's August 21, 2003 Order Adopting 25.501.

Economic efficiency, impacts related to different siting signals, and changes in congestion management are addressed as part of this EIA, as are potential energy price shifts and other potential impacts to consumers related to the cost to serve load. Other impacts, such as transparency and volatility associated with market changes outside of those measured in the EIA, are addressed in Section 6, Other Market Impacts.

3.2 Measuring Benefits with the Energy Impact Assessment

Four primary metrics[17] were used in the EIA to quantify the impacts of the nodal market design:

1. Production costs (fuel and variable operating and maintenance costs)
2. Revenues to Generators
3. Cost to Serve Load
4. Congestion Payment Impacts

To illustrate how to quantify the impacts of the market design using these metrics, consider how nodal pricing can impact economic efficiency.

> *Production Cost:*[18] In the Change (Nodal) Case, by including all constraints in a single optimization, there is a potential increase in the economic efficiency of dispatching generation resources to meet demand at lowest cost, and this could lower the total cost of producing electricity. This is a result of the ERCOT operator's ability to control the system using actual unit-specific shift factors rather than having to control the system more conservatively (through the use of transmission line operational limits). If a more efficient dispatch results, then system costs will decrease. Production costs in the Change Case can also change over time because of more efficient siting of generating resources.
>
> *Revenue to Generators:* Revenue to generators is not particularly a measure of the merits of one case or another, but rather reflects the revenue impacts to generation owners.
>
> *Cost to Serve Load:* The cost to serve load reflects the energy cost impacts to load-serving entities and ultimately to downstream consumers. While there may be a net social welfare increase with the Change Case, it is possible that the cost of energy to serve load, as strictly measured through the simulated energy results, could be higher in the Change Case. This metric reflects these costs.

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[17] Note that these metrics are not entirely independent. That is, a widespread reduction in production costs is likely to have an effect on the net impacts to load, namely the cost to serve the load adjusted for congestion payment impacts.

[18] The Production Cost metric is used throughout the EIA. In this analysis, where it is essentially assumed that demand is inelastic and where the demand is the same in both the Base and Change Cases, the production cost saving is expected to be the change in social welfare. Note that the social welfare, and the consumer and producer surplus, are economic terms that are often used in cost-benefit analyses. In practice, this concept is applied by governments to aid decisions that affect society, e.g., in deciding to build roads or preserve wilderness areas, in building recreational sites, or requiring environmental mitigation measures. Thus, to the extent one finds the construct of social welfare more useful, the change in production cost can be viewed as equivalent to the change in social welfare.

In the Base Case, the cost to serve load is the total market cost of energy in each zone—the Marginal Clearing Price of Energy (MCPE) in each zone times the quantity of energy in that zone—plus the uplifted cost of OOME and other uplifts associated with the simulated system.[19] In the Change Case, the cost to serve load is the LMP of the load zones times the energy in each load zone, plus the uplifts associated with the simulated system.

In the EIA, the entire ERCOT system is treated as an energy market. In this paradigm the broad extension of this spot market construct is made by suggesting that the cost to serve load consists entirely of load purchases through this simulated spot market. In this simulated mode, the bilateral market layer, or any other long-term forward or financial markets, are not explicitly treated. Instead we represent this cost to serve load measure as if the entire load was purchased from this simulated spot market.

This means that these simulated results would not emulate expected real-world immediate load results because load-serving entities instead have a mix of long-term contracts, fixed price contracts, etc. However, the long-term markets would be expected to be correlated with the spot market behavior in the long run. Given that this modeling effort simulated the physical behavior of the system and the spot market impacts, it is not possible to measure other than these spot market impacts.

The net impacts to loads cannot be determined only based on the cost to serve load, given the collection of excess congestion rents (load payments that exceed generation costs). This is especially true in the ERCOT markets, where there is a very direct feedback of excess congestion rent revenues to parties representing loads. In other words, in a nodal spot market, for example, the load-serving entities will procure their energy at the LMP. To the extent there is congestion, this will result in an over collection of funds by the system operator; the loads will pay more than the generators will be paid. This excess congestion revenue is then refunded to the Qualified Scheduling Entities based on load share. Net impacts to loads therefore will be the combined impact of the cost to serve load and the congestion payment impacts. The treatment of these rents is discussed next.

Congestion Payment Impacts: It is possible, if not likely, that a nodal market design will result in a decrease in production costs yet cause an increase in the cost to serve load. This is because more of the constraints in the system would be priced marginally in this case. To the extent there is congestion, this will result in an ERCOT over collection of funds from energy transactions; the loads will pay more than the generators will be paid. This excess congestion revenue is then refunded to the Qualified Scheduling Entities (QSEs) based on ERCOT-wide load share. The congestion rents are presented in the results section and used to determine the net impacts to loads.

The GE-MAPS model is a security-constrained dispatch model that simulates the operation of the electricity market over time. It assumes short-run marginal cost bidding,[20] performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly LMPs for electricity. Because it is reasonable to assume that real markets are not perfectly competitive, the simulated prices represent the lower bound of what actual market prices are likely to be. For the Zonal Case the GE-MAPS model was used iteratively, as described in Section 3.2.4.1 below. Zonal MCPEs were derived by examining the congestion when only considering the Commercially Significant Constraints (CSCs), and local congestion was not priced marginally.[21] For the Change Case, load-weighted average prices were calculated to reflect the load zone pricing policies envisioned.

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[19] Note that GE-MAPS uses a unit commitment process, although there is no formal unit commitment process in ERCOT. For each simulated year and case, GE-MAPS calculates an uplift resulting from commitment constraints each hour, such as minimum up times.

[20] The assumption of short-run marginal cost bidding can be overridden, implementing strategic bidding behavior, but the effort required to do this is considerable; prior to the contracting process, the CBCG chose not to pursue this approach. Note that throughout this report the use of the term "marginal cost" means refers to short-run marginal costs.

The GE-MAPS simulation is consistent with the congestion management scheme envisioned by ERCOT for settling the real-time spot market. GE-MAPS simulates the electricity market by dispatching resources to serve load in a least-cost manner, subject to the operational constraints imposed in the Zonal Case to manage the use of average shift factors. The bidding strategy that is assumed is based upon the marginal cost of generation and therefore reflects the locational marginal price of electricity at specific nodes. Nodal data can be aggregated to any level desired (utility, region, state, etc.).

3.2.1 Input Assumptions

The following inputs assumptions were used in the EIA:

- A load forecast based on most recent forecast as provided by ERCOT
- Gas and Oil forecasts as described in the forecast memo
- Coal forecast as purchased from Resource Data International
- A transmission system configuration based on a load flow representation that includes all planned transmission upgrades, as provided by ERCOT
- Environmental adders based on expected environmental regulations
- New generation additions already under construction based on information from ERCOT

Details of these and other inputs to the model are described in Appendix 3-1 (Assumptions), Appendix 3-2 (Fuel Forecast Memo), and Appendix 3-3 (Additional Environmental Modeling Details).

3.2.2 Overview of Base and Change Cases

The EIA fundamentally compared two scenarios: a Base Case, assuming no implementation of a nodal market, and a Nodal (or Change) Case, representing operations with ERCOT with a nodal market in place.

The following represents a summary of the Base and Nodal Cases. Detailed discussion for each major attribute is provided in the sections that follow.

The essential differences between the Base and Change Cases relate to: (1) how congestion is cleared and energy prices are set, given this congestion clearing mechanism, and (2) the treatment of portfolio scheduling under the Base Case vs. no portfolios under the Change Case. In the Change Case a pure nodal optimization is performed across the ERCOT region, and prices are given by the LMPs. Generators are priced directly at their nodal LMPs, and loads are priced based on the load zone load-weighted average of the load node prices. In the Base Case, ERCOT's existing zonal model is simulated. The siting of new generation is based on the resulting prices, and the decision rules used in the simulation to site vary given that there are different pricing signals under the Base Case than the Change Case. Siting criteria are discussed in 3.2.6.

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[21] For local congestion resources providing congestion resolution are instead paid directly for the cost of resolving the constraint, but this value does not set prices in any other manner.

3.2.3 Regional Least-Cost Dispatch

The GE-MAPS feature of committing generation resources on a regional basis (equivalent of the day-ahead market) and dispatching generation units on the ERCOT-wide basis was used in both cases.[22] The objective was to capture all the economy transactions that currently take place among various entities in the ERCOT and those to be expected following implementation of the Texas Nodal Model (TNM). Doing this represents an assumption that outside of the market structure influences, the wholesale electricity market in the ERCOT is currently efficient and that the TNM will not increase the efficiency of the trading market. (This is a conservative assumption that does not capture the increased efficiency of the ERCOT market that would arise (if any) from implementing the TNM in ERCOT.)

3.2.4 Transmission, Congestion, and Energy Pricing in Base and Change Cases

The underlying transmission system representation was given by the load flow models provided by ERCOT. In addition, a list of contingencies was also provided by ERCOT. TCA developed a list of constraints to be monitored by the GE-MAPS model by performing an analysis using the MUST application. ERCOT provided TCA with a list of contingencies, described as the "PLANNING Category B contingencies updated August 14, 2003." TCA used the PTI MUST software to perform a DC contingency analysis of the provided load flows, using this list of contingencies. From this analysis, TCA obtained a set of constraints (i.e., monitored line-contingency pairs) that were likely to bind. This set was monitored in the GE-MAPS model. Included in this set were the following:

- All non-radial lines ≥69 kV that were loaded at least 50% in the load flows;
- Contingency constraints that have been shown to bind in ERCOT's planning models;
- All the contingency constraints in the CSC definition files from 2003 and 2004, including the closely related elements (CREs).

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[22] The GE-MAPS model first solves the unit commitment problem for the next day using a heuristic approach and then solves for the hourly dispatch using a linear programming approach to achieve the least-cost, most efficient hourly dispatch subject to all reliability constraints for that unit commitment solution. The transfer capabilities (i.e., transmission constraints) of the transmission lines and major interfaces are inputs to the model and are based on the thermal capabilities of the transmission system or the equivalent transfer limits for voltage and stability constraints. The model can represent nomograms, which are more accurate representations of voltage and stability constraints.

TCA also implemented the Remedial Action Plans (RAPs), which provide for certain constraints to be managed operationally, prior to the execution of any energy price determination. Similarly, TCA implemented ERCOT's Special Protection Schemes as defined by ERCOT's planning department. In addition, TCA and ERCOT identified constraints that were found in the modeling to be binding in a manner that prevented the constraints from being resolved economically a significant number of times throughout the simulation year.[23] The resulting constraints used in the GE-MAPS model are posted at <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=66&b=>

Use of the constraints differs under the Base and Change Cases. As stated above, the Change Case uses the constraints directly and clears all constraints simultaneously in an optimal dispatch, whereas the Base Case treats CSCs differently than local constraints. The following descriptions detail the Base Case and Change Case representations in GE-MAPS. Also provided is a summary of the differences between the model representation and the existing reality of the Base Case or the anticipated reality of the Nodal Case.

3.2.4.1 Base Case Representation

The Base Case modeling mirrored the way that ERCOT manages zonal and local congestion in today's market environment and reflecting the software Releases 3 and 4. Generally, ERCOT follows three primary steps:

- Step 1. Estimation of zonal congestion and energy balance
- Step 2. Resolution of local congestion, subject to results of Step 1
- Step 3. Final resolution of zonal congestion and energy balance subject to results of Step 2 and formation of zonal prices

To emulate the Base Case three-step process, TCA created two instances of the GE-MAPS model, one simulating the results of Step 1 above and calculating zonal prices, the other simulating the outcome of Steps 2 and 3. In addition, TCA developed post-processing software for calculation of the Out-of-Merit Order Energy settlements. The first instance of GE-MAPS is based on the zonal representation of the ERCOT electrical system. This model employs GE-

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[23] Constraints must have been found to be binding for at least 24 hours of the year and to be binding in a manner in which they could not be economically resolved by the model at least half of the binding hours. Such constraints were then deemed, for the sake of modeling, to constitute constraints that must be managed operationally rather than economically, and they were excluded from economic treatment within the CB simulation models. TCA conducted several iterative analyses of those constraints. The results of those analyses have been reviewed by the ERCOT staff for validity. In reviewing these results, ERCOT staff recognized some of these constraints to be treated though RAPs or being associated with known Special Protection Schemes. There are, however certain constraints that could be economically managed in some hours and could not be economically resolved in other hours. TCA models allow these constraints to overload using the overload cost of $700/MWh. Without making such a modeling assumption, a continuous modeling of the ERCOT system for the purpose of CB would not be possible. Costs of overload constraints constitute a measurable portion of total congestion costs as shown in the table below, which indicates the portion of congestion costs attributed to the overloads.

Year	2003	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
%Overloads	15	28	27	26	29	6	13	24	22	26	34

These overload costs, however, do not dominate the results.

MAPS, a security-constrained unit commitment and dispatch optimization algorithm subject to CSC constraints only.

The topology of the electrical system in that instance of GE-MAPS is designed in such a way that all generating units within a zone have identical shift factors with respect to each CSC, equal to the weighted average of actual shift factors in a zone. CSC limits are set below Total Transfer Capability (TTC) to replicate the operational rule used by ERCOT in managing inter-zonal congestion using average shift factors. In reality, ERCOT's Operational (OC1) limits change minute by minute along with market conditions. In simulating the zonal market, TCA assumed that TTC and OC1 limits remain constant over time. The reduction in transmission capacity approximating the difference between TTC and OC1 operating limits was calculated by taking one standard deviation below the mean flow limit, based on a distribution of possible flow limits[24] given the uncertainty introduced by using zonal average shift factors instead of nodal shift factors. This distribution was established by calculating the generation-weighted standard deviation of flows (flow times shift factor) from each bus in a given zone with respect to each CSC. The result was a matrix of standard deviations that could be used to estimate the standard error in flow impact on each line from each zone. Table 3-1 shows the resulting derived Operational Limits

Table 3-1 CSC TTC and Derived Operational Limits

Constraint	**2004 Total Transfer Capability (MW)**	**Peak Generator Flow (MW)**	**Error (%)**	**Estimated OC1 Limit (MW)**
West–North	534	2,844	1.3	500
South–North	701	11,888	0.8	600
South–Houston	736	482	28.5	600
North–Houston	1223	10,567	0.7	1150
North–Northeast	829	1,043	5.4	775

In this simulation no local constraints were enforced. From this simulation, the dispatch by unit by hour was extracted.

The second instance of GE-MAPS combines the resolution of all local constraints using actual shift factors subject to honoring CSC constraints based on the TCA-derived OC1 physical limits (as if addressed in the zonal framework using average shift factors) as well as all contingency constraints associated with all Closely Related Elements (CREs) associated with CSCs. The dispatch simulated by the second instance of GE-MAPS reflects the outcome of Steps 2 and 3 of the ERCOT dispatch process.

Post-processing was then performed to determine the payments to generators based on the combination of simulations, and the ERCOT pricing policies for resolving local congestion. Payments to generators by unit by hour were calculated according to the following rules:

- If in an hour a unit was not resolving local congestion it was paid the zonal MCPE for its output.
- If in an hour a unit was resolving local congestion this unit was paid the zonal MCPE for its energy dispatch under the zonal model plus the maximum of its costs or the MCPE for the output it was incremented, or the minimum of its cost or the MCPE for the output it was decremented;

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[24] In other words of the set of all possible flow limits, TCA used the mean of this set.

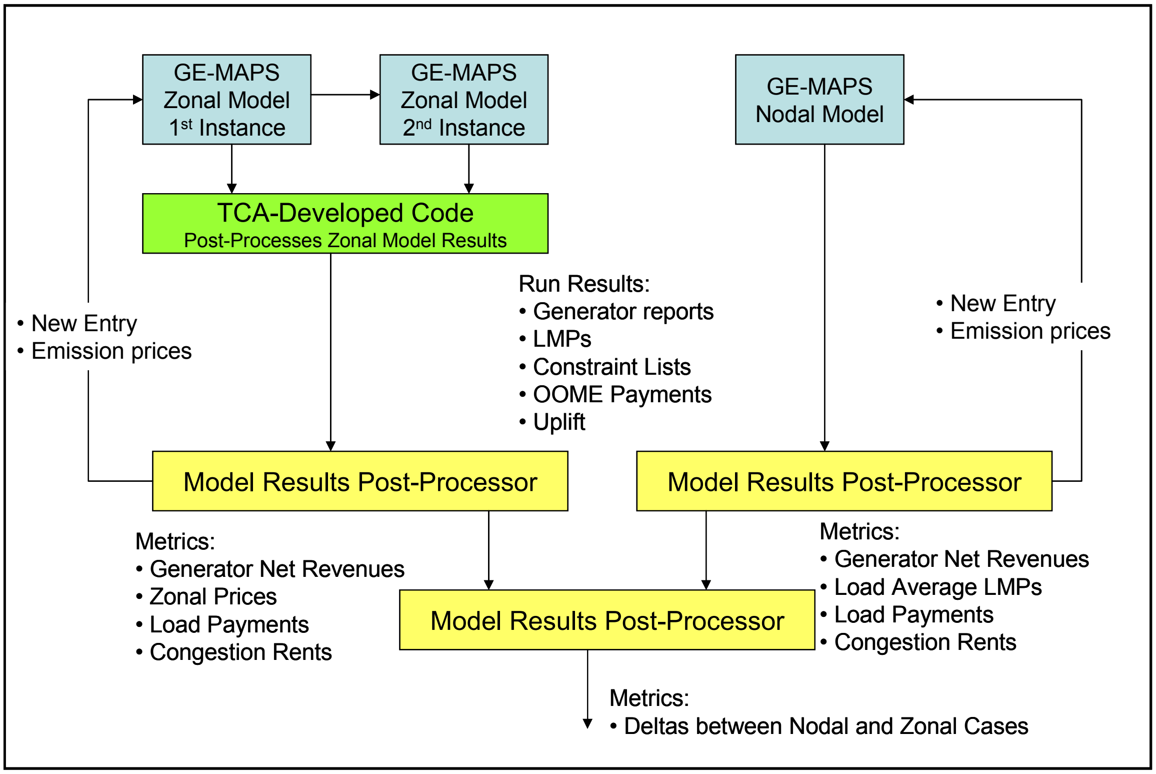
- A unit was considered as resolving local congestion in a given hour if its dispatch in the second instance of GE-MAPS was different from the dispatch in the first instance of GE-MAPS in that hour.

3.2.4.2 Change Case Representation

The Nodal Case simulations were performed using GE-MAPS' security constrained unit commitment (SCUC) and dispatch algorithms with all economic constraints (other than those that cannot be resolved economically, as described above) enforced. In this case a single simulation was performed, and the resulting LMPs and generator payments were used to develop the metrics discussed in the results sections.

Figure 3.1 shows a schematic diagram of the representation of both the Base Case and the Change Case representations, including the GE-MAPS portions of the modeling, algorithms developed by TCA, and post-processing analysis.

Figure 3-1 Schematic Flow Chart Representation of EIA Data Flows


GE-MAPS Zonal Model 1st Instance
GE-MAPS Zonal Model 2nd Instance
GE-MAPS Nodal Model
TCA-Developed Code
Post-Processes Zonal Model Results
Run Results:
• Generator reports
• LMPs
• Constraint Lists
• OOME Payments
• Uplift
• New Entry
• Emission prices
• New Entry
• Emission prices
Model Results Post-Processor
Model Results Post-Processor
Metrics:
• Generator Net Revenues
• Zonal Prices
• Load Payments
• Congestion Rents
Model Results Post-Processor
Metrics:
• Generator Net Revenues
• Load Average LMPs
• Load Payments
• Congestion Rents
Metrics:
• Deltas between Nodal and Zonal Cases

3.2.5 Treatment of Portfolio Bidding

This section discusses the topic of portfolio bidding, comparing features of the current market design and the Texas Change Case with their parallel simulated Base and Change Case representations.

One concern regarding the Base Case (zonal) market design is that portfolio bidding—while giving market participants flexibility to optimize their own systems—may have some undesired impacts on market efficiency. It was an objective of some or all interested parties to this study to examine the impacts of portfolio bidding.

GE-MAPS performs a least-cost dispatch for each unit, independently, within the ERCOT control area. Given the use of an optimal dispatch tool for the EIA, there are aspects of the Base Case market structure that are not reflected in the GE-MAPS modeling. That is, the GE-MAPS model behaves as if every market participant always makes the optimal decisions based on the market structural characteristics reflected in the model. In this regard with respect to portfolio bidding, there is no way to model the efficient dispatch of the system without modeling the efficient dispatch of the system; by virtue of trying to model the efficient dispatch of the system, the study method itself limits the extent to which the actual inefficiencies can be reflected.

The following table compares aspects of portfolio bidding and the extent and manner in which they are addressed in the EIA.[25]

Table 3-2 Treatment of Market-to-EIA Portfolio

	Base Case Market/Operations	Base Case EIA	Change Case Market/Operations	Change Case EIA
Energy Bidding/ Scheduling	Portfolio → unit-specific translation by ERCOT	Unit Specific	Unit Specific	Unit Specific
Shift factors for zonal management	Zonal Average	Zonal Average	N/A	N/A
Shift factors for local congestion management	Actual	Actual	Actual	Actual
Energy Dispatch	Portfolio, Given average shift factors	Unit-specific, Given Average shift factors	Unit-specific	Unit-specific
Operational transmission limits imposed?	Operational Limit imposed for zonal market	Operational Limit imposed for zonal market	No	No

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[25] Note that there are additional attributes related to portfolio bidding and scheduling limits not reflected in this table. These include such matters as the ERCOT operators' ability to know precisely which units are operating to measure congestion on local constraints and the portfolio impacts on other Ancillary Service market bidding, scheduling, and selection processes. Other aspects are not indicated because the areas they impact are not treated in the EIA. Other non-EIA impacts are addressed in Section 6, the OMIA.

As shown in the table, the EIA provides a nearly complete representation of the portfolio differences, yet does not capture any efficiencies or inefficiencies[26] associated with a participant's own management of their portfolio versus full optimization by the system operator. The study results will therefore reflect the inefficiencies imposed on the system through the use of average shift factors and the implementation of lower operating limits on the CSCs required (based on the fact that the operators do not have full knowledge of actual flows under the portfolio scheduling process). Conversely, the model does not reflect the potential suboptimality of a participant's choice of resource deployment *within* an individual portfolio. Further, the model does not reflect ERCOT operators' lack of knowledge regarding which resources will be deployed to what levels within a participant's schedule.

As with any input assumption, it is useful to ask: how will this impact the results, and particularly, will this bias the Base Case over the Change Case or vice versa? That is, does this simplification impact the difference in the cases and if so, would it tend to overestimate or underestimate the results? Clearly, to the extent that participants today choose inefficient portfolio deployments and to the extent that they choose to offer these resources to ERCOT's market for optimization under the TNM,[27] then the EIA under captures the benefits of the TNM. Furthermore, regardless of participants' effectiveness in optimizing their own behavior, the resource schedules are known to the ERCOT staff to a greater extent under the TNM; ERCOT's improved ability to represent self-schedules accurately will create benefits that are not captured by the EIA. In this sense the EIA underestimates the efficiency gains of the TNM.

3.2.6 Adding Economic Resources in the Base and Change Cases

TCA added those resources that are already under construction in accordance with the timing assumptions provided by ERCOT and as captured in Appendix 3-1.

Beyond those facilities already under construction, TCA added resources to ensure an ERCOT reserve margin of 12.5% was maintained. Appendix 3-1, containing the Assumptions Memo, describes generally TCA's decision rules for whether new generating resources are developed in a particular year and what type of resources are developed. Determination of the location and technology type is different under the Base Case and the Change Case. In both cases the general objective of the economic new entry logic is, all else equal, to site generators where they will be most profitable given system payments.

Under the Nodal Case, LMPs are used at each high-voltage bus to compute the spark-spread value of each generating technology if connected to the grid at that bus.[28] The spark-spread value is then subtracted from the carrying charge for that technology for a given location (e.g., carrying charges in the metropolitan area locations were 25% higher than elsewhere). The best technology for the given location is then determined as one that has the lowest revenue deficiency (difference between the carrying charge and spark-spread value). That number determines the index of the location. Locations are then ranked from the lowest index to the highest and with the type of generation technology determined. New resources are then added one by one at each location starting with the one having the smallest index.

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[26] In this EIA it is generally assumed that the centralized optimization mechanism will "alleviate any inefficiency with" portfolio bidding. However, a centralized system optimization does not necessarily result in a more optimal outcome. This will only be the case if the optimization includes all significant decision factors, but centralized optimization models do have simplifying representations. Since the EIA only measures optimality using its decision rules in both cases, this outcome is not reflected in the EIA. Instead, this topic is discussed in the OMIA.

[27] Similarly, if a participant that inefficiently manages its portfolio today continues to self-schedule its resources under the TNM, then any incremental efficiency will not be experienced.

[28] The spark-spread value is calculated as per-kilowatt net revenues a generator of certain technology type would earn given its technical and economic characteristics.

In the Base Case, however, TCA assumed that market participants would have less information about the expected revenues in that participants would only have knowledge about the value of specific locations where units are already located. In the absence of locational prices, spark-spread values could be computed only on the zonal basis. The spark-spread values could then only be complemented by estimates of OOME payments in the form of OOME per-kW-year adders to spark-spread values[29]. The OOME estimates, however, are available only for existing generating sites and are not known for any other bus, making all other locations economically uncertain or unattractive. TCA therefore assumed that units would only be sited near other generating plants. In addition, TCA assumed that there is less information regarding what the OOME payments would have been where similar technologies do not exist (e.g., what OOME payments a coal plant would have received at a location where there is now only a combined-cycle plant). Given these assumptions, TCA used the following siting rules for the Base Case:

- Units would only be sited near other generating units and would not otherwise be sited at load nodes.
- Specific OOME Up and OOME Down information at a node would be used if a plant of similar technology was being assessed, but if a plant of one technology was being considered for a location where there was only currently existing a different technology, then the zonal average OOME payment would be used by TCA to represent the expected OOME payments to this new technology at that site.

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[29] Note that once the simulations were underway, two factors prevented the strict implementation of this siting strategy in the out years of the study. First, beyond 2009 no transmission upgrades were specified by ERCOT and thus none were assumed in the study. Secondly, siting based on OOME Down payments creates a positive feedback loop: the need for OOME Down creates an OOME Down payment that encourages generators to site at that location, further elevating the need for OOME Down, and so forth. Given the relationship between these dynamics the output of the units added based on OOME Down could often not be delivered to meet the capacity needs of the system, and thus TCA stopped using OOME Down payments as a criteria for siting for the 2012 – 2014 years.

3.2.7 Other Potential Differences: Modeling Representation vs. Actual

This section highlights other significant modeling representations that differ from the actual ERCOT zonal system design. Table 3-3 presents these differences and, where possible, identifies the manner in which the difference indicates that the EIA relative (Change Case – Base Case) impact results will deviate from the expected actual relative impacts.

Table 3-3 Impacts of Other EIA Modeling Representational Differences

Topic	Modeling Representation in EIA	ERCOT Design (Current and TNM)	Effect on Impacts (Change Case – Base Case)
Energy Optimization Includes Optimal Commitment	Security Constrained Unit Commitment and Economic Dispatch	No security-constrained unit commitment co-optimization currently with either Zonal or TNM pre-EHDAM. SCUC at real time with zonal and with RUC for TNM.	To the extent the commitment efficiency increases with the TNM, the EIA understates the improved efficiency.
Commercially Significant Constraint (CSC) Total Transfer Capability (TTC) and Operational Limits (OC1 Limits)	CSC TTC and OC1 limits are assumed to be fixed throughout the study period	Study time horizon, 2005-2014 has transmission upgrades that occur between the years 2005 and 2009. With these upgrades it is possible that the transfer capability of one or more of the CSCs would improve or that the operational limits could be relaxed.	To the Base Case congestion limits imposed of the CSCs on generation dispatch under the Base Case are overly restrictive, generation costs under the Base Case would be overstated.
Optimal Energy Dispatch	Energy dispatch is optimal	Current optimization in real time, given zonal model and portfolio bidding limitations (described in Section 3.2.5); optimized for real time in TNM, and EHDAM[30] provides optimal forward schedules for those participating in market.	It is likely that actual market outcomes in the current market design will be more suboptimal (relative to the modeling) than will market outcomes in the TNM given the market systems and EHDAM mechanisms to promote optimal scheduling and dispatch. To this extent, the EIA would underestimate benefits.
Co-optimization of Operating Reserves	Spinning reserves are co-optimized in GE-MAPS for the unit commitment outcomes. Spin is not co-optimized as part of the energy dispatch algorithms	Neither the current market nor the currently contemplated TNM design employs co-optimization.	Second-order effect that is not expected to significantly drive the measure of impacts between the two cases.

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[30] Enhanced Hybrid Day-Ahead Market.

Topic	Modeling Representation in EIA	ERCOT Design (Current and TNM)	Effect on Impacts (Change Case – Base Case)
	for the EIA		
Marginal Cost Bidding	All units are dispatched based on their short-run marginal cost	To the extent any generation owners have market power, they may be able to profitably bid above short-run marginal cost or self-schedule generators in order to collect OOME Down. If OOME Down could be collected on a sustainable basis, owners might have an incentive to self-schedule and/or bid their units below marginal costs.	Would drive measure of relative impacts only to the extent that one case or the other creates a greater propensity for the exercise of market power. The direction of bias on measured impacts is indeterminable. To the extent that the OOME Down-related market power is present, EIA results would tend to understate the benefit of TNM.
Regulation and Reserve Markets	Regulation and reserve markets are not represented in the GE-MAPS model	Such markets exist	EIA will not measure impacts of improved efficiency in these markets.
Bilateral Trading and Financial Markets	The EIA captures only the fundamental physical representation, which can be viewed as a spot market analogous representation. The financial layer of the bilateral trading market cannot be represented in GE-MAPS. Similarly, transmission rights markets are not represented in the GE-MAPS EIA modeling.	Bilateral markets constitute a significant fraction of market activity and are expected to do so under the TNM design. Financial markets are also important in both market paradigms.	The absence of the representation of these markets will bias the measurement of the relative fundamental benefits of the EIA. The EIA does not capture bilateral market impacts, but the EIA impacts should reflect the propensity for bilateral and financial market efficiency.
Generating Capacity Addition Decision Parameters	Based on economics of energy revenues and plant costs, and somewhat on the availability of high-voltage transmission. Premium for siting in metropolitan areas	Actual siting also requires ability to site, rights of way, water, fuel supplies, etc.	Other siting constraints impact siting in both the Base and Change Cases. To the extent that it would be less possible to site in specific locations in response to LMP price signals, the EIA benefits of improved siting would overstate actual benefits.

3.3 Summary of Results

The results of the EIA GE-MAPS analysis are summarized in this section. The section provides the quantification of impacts, changes in energy prices, and resulting transmission constraints for the Base and Change Cases. All financial values shown in this section are expressed in real year-2003 U.S. dollars.

The quantification of benefits from the GE-MAPS analysis is based on comparisons between the two cases[31] and includes generation production cost, load payments based on spot market purchases, and generation revenues based on spot market payments. The comparisons are made across the ERCOT system. In addition, some[32] of these metrics are applied regionally and by segment in this section, in addition to the summary provided in Section 7.

Results are presented for both the changes in the value of energy to loads[33] and the generators' revenues (based on the value of energy at the generator busses). The analysis also reports on impacts related to congestion rents and congestion payments.

Both the load costs and the generator revenues reported here consist of several components, including energy and uplifts. The energy revenue or payment is the marginal value of energy at each load bus multiplied by the volume of energy delivered or consumed. The uplift is an accounting of funds needed to "make generators whole" across each operating day, should the most economic solution dispatch a generator that subsequently does not recover its startup costs through energy net revenues. Further, in the Base Case, the OOME is an uplifted payment stream (payments to generators and costs to loads).

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[31] Capturing benefits in this way removes the majority of concerns regarding inaccuracies in modeling variables, because the great majority of parameters act equally in both the Base and Nodal cases. By examining differences between the cases, therefore, one can eliminate adverse impacts of a majority of modeling assumption inaccuracies.

[32] Note that the regional and segment analyses are distinct from the ERCOT system analysis because for each type of analysis there is a less complete balance, though for different reasons. For the regional analysis, there are hourly flows between the zones that render a full accounting of each regions' impacts infeasible, and for the segment analysis, the segments studied are not necessarily comprehensive.

[33] As was stated earlier, the Energy Impact Assessment calculates the marginal price of energy. For calculating benefits, the value of the energy consumed by the loads is calculated as the marginal price of energy at each load bus multiplied by the load consumption at that bus. These are the values that are compared between the Base and Change cases. Throughout this analysis, other, more concise terms are used to represent this value. It should therefore not be assumed that when terms such as "Load Energy Payment" or "costs to loads" are used, TCA presumed to know what loads would actually pay. That depends on many factors, including future rate design issues (such as the "Price-to-Beat" policy), which are outside the scope of this analysis.

3.3.1 Time Frames in the Forward Analysis

Based on the results of the analysis, the modeling horizon can be seen as falling into three time periods, each of which has different characteristics.

1. Near-term (2005–2008)
   - Transmission upgrades are explicitly considered with the transmission model changing every year (provided by ERCOT)
   - Surplus supply–demand conditions are satisfied through 2008 subject to announced capacity additions
2. Mid-term (2009–2011)
   - No transmission upgrades are modeled; ERCOT 2009 load flow case is used
   - Resource capacity is added subject to market signals created within each market framework
   - Transmission system appears capable of accommodating capacity additions
3. Long-term (2012–2014)
   - No transmission upgrades are modeled; ERCOT 2009 load flow case is used
   - Transmission system is no longer capable of accommodating resource capacity additions based on purely economic criteria
   - Resource capacity addition process is no longer formalized, and is driven by “trial and error” methods to find feasible placement scenario

TCA believes that specific predictive conclusions should not be based on TCA results obtained for 2013, and especially 2014. This is because the massive addition of new generating resources modeled for out years is not supported by transmission upgrades.

3.3.2 Explanation of Benefits

The following metrics are provided to characterize the energy impacts. Each metric is discussed below.

- Physical metrics: quantities of supply and demand
- Cost and revenue metrics
  - Generation costs, revenues and margins
  - Costs of serving loads
- Load impact with excess congestion rent refunded to loads
- Regional analysis (by zone)
- Segment analysis (by participant type)
  - Generation side
  - Load side
- Energy price analysis
- New-entry analysis
- Generation mix comparisons

3.3.2.1 Physical Metrics

The total generation is essentially the same in the Base and Nodal Cases because there is little interchange between ERCOT and surrounding regions. The differences can be attributed to small changes in imports or exports (given the representation of import/export flows as dependent upon the ERCOT price). Figure 3-2 shows the generation in each simulation year.

Figure 3-2 Total Generation

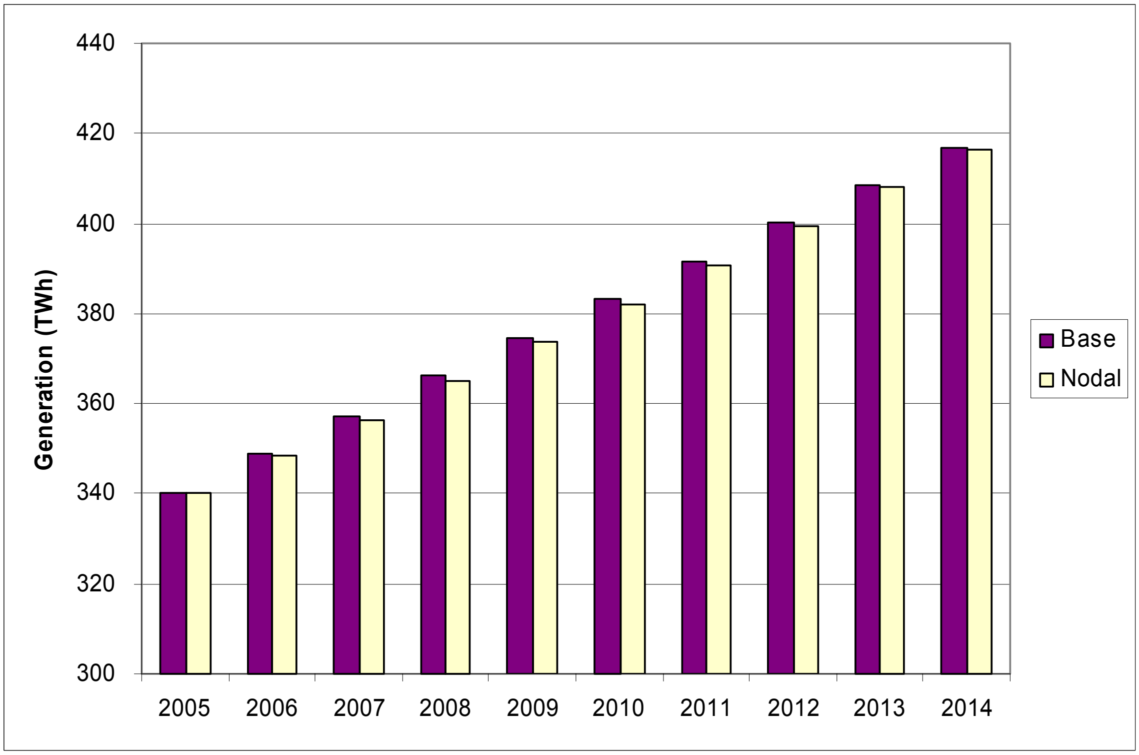
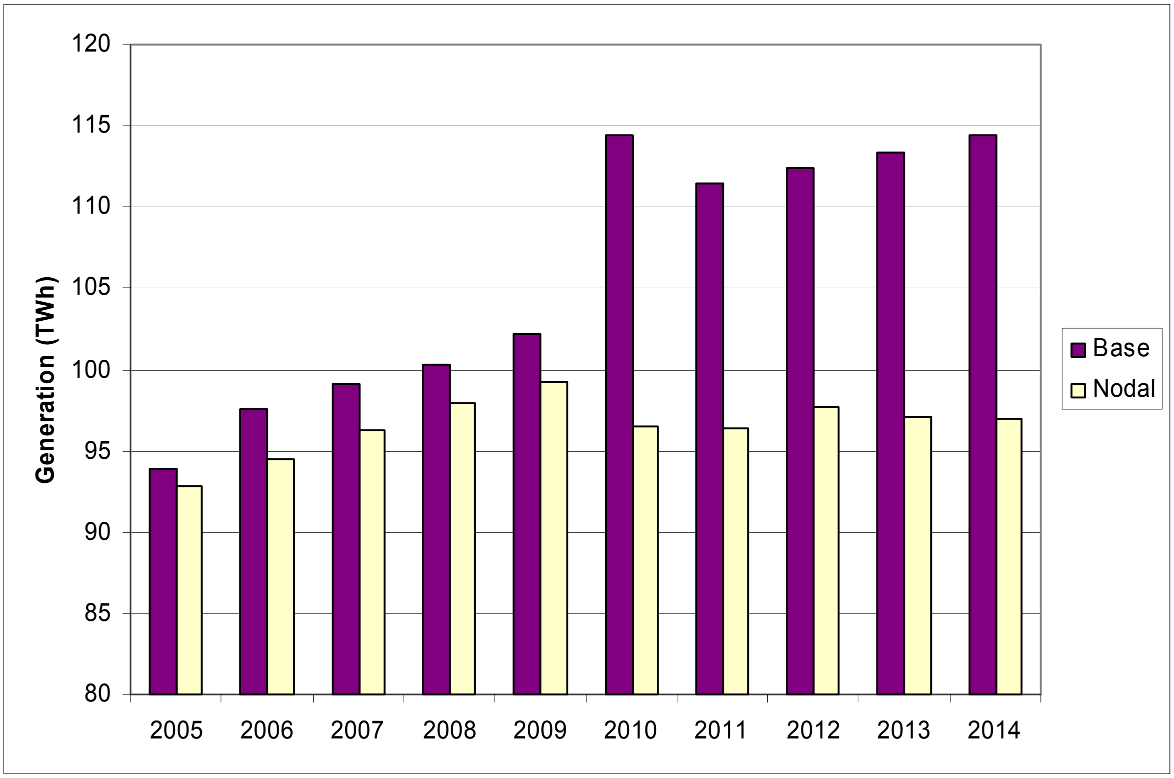


Figure 3-3 through Figure 3-5 show the generation in the Houston, North, and Northeast zones respectively.

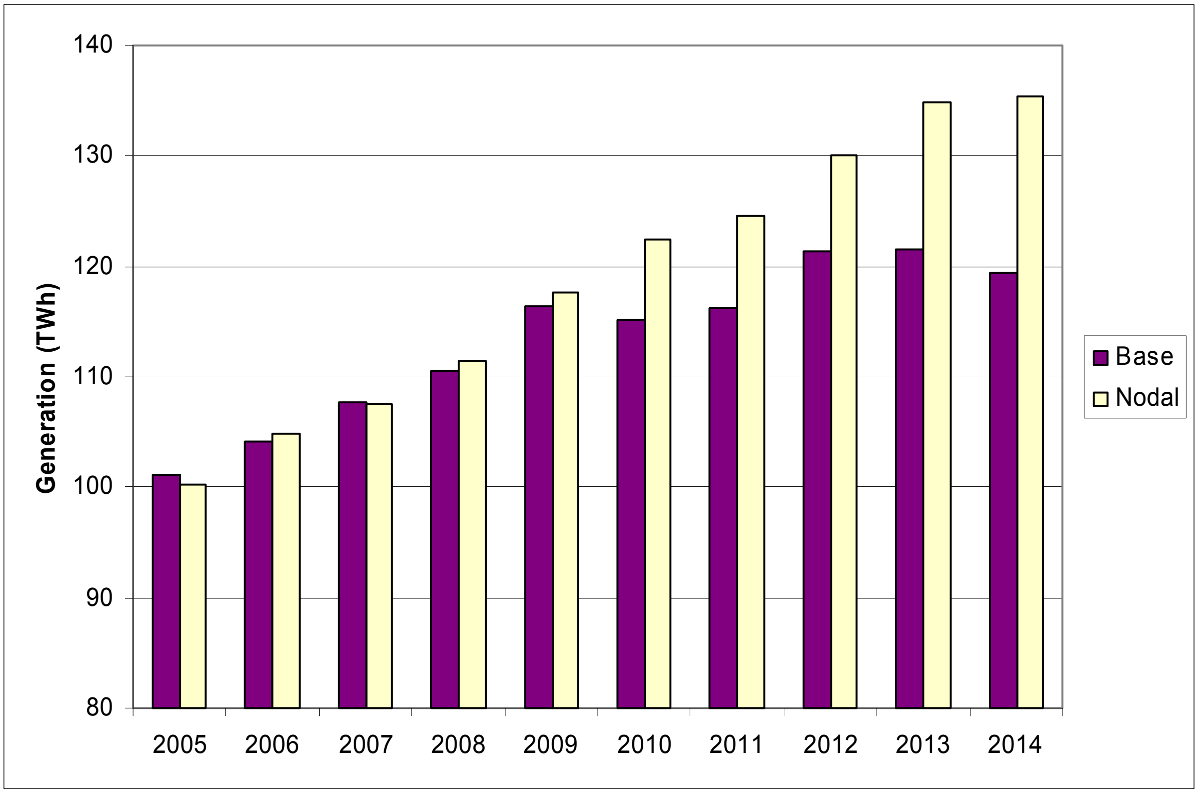
In Figure 3-3 for the Houston zone, in the near-term, the nodal market improves congestion management and allows generation imports into Houston. Hence Nodal Case generation is less than the Zonal Case congestion. In the mid-term, new efficient capacity is added in Houston in the Zonal scenario, because zonal market signals suggest additions in that zone. No additions occur in Houston in the Nodal Case. Hence Zonal Case generation is much greater than Nodal Case generation. The long-term picture is a continuation of the near-term trend.

Figure 3-3 Generation in Houston



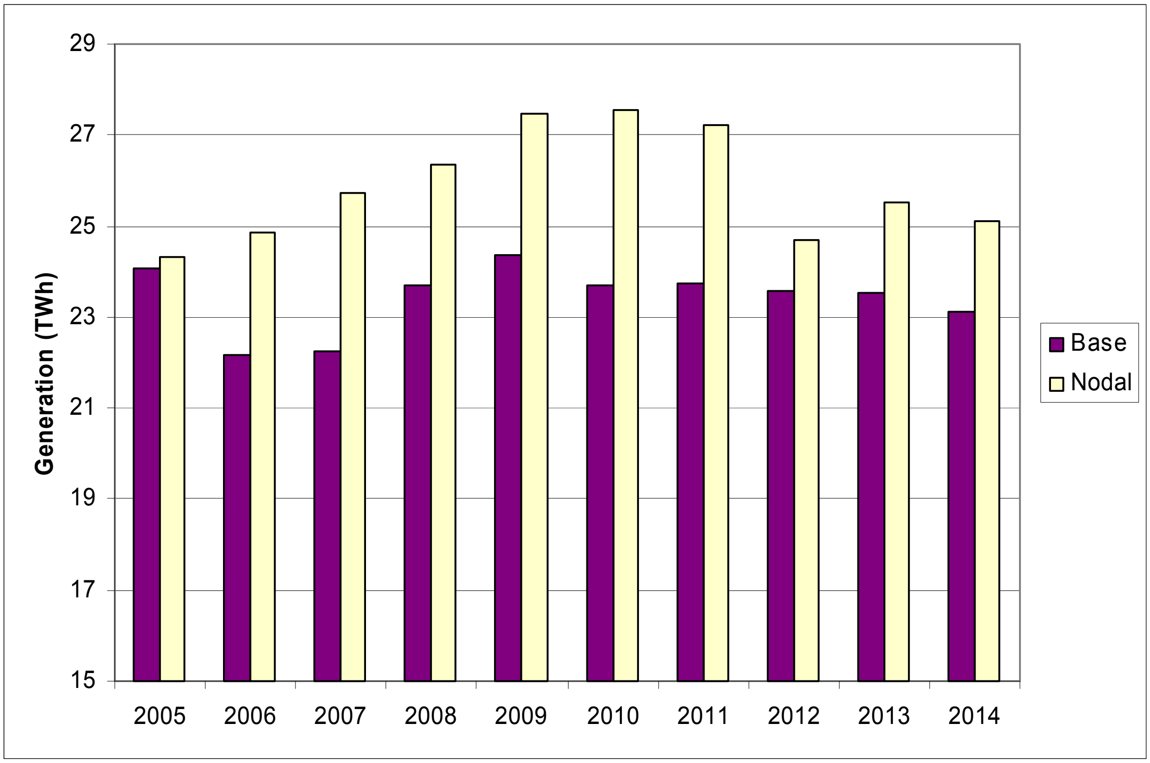
In the North Zone, shown in Figure 3-4, generation in the North is almost unaffected by market redesign in the near-term. However, in the mid-term and long-term more generation occurs in the North under the nodal design. This is because the nodal market structure creates more incentives to site generation in the North than the Zonal structure does.

Figure 3-4 Generation in the North



The Northeast Zone, shown in Figure 3-5, also shows more generation under the nodal structure than under the zonal.

Figure 3-5 Generation in the Northeast



Generation in the South and West Zones (not shown) shows less impact from the nodal market design. Generation in the South is almost unaffected. Generation in the West is approximately 5% lower under the nodal structure than under the zonal structure.

3.3.2.2 Annual Generation Costs—a critical economic indicator

Annual generation cost is a critical economic indicator. It is easy to interpret and it clearly represents a social gain (social welfare gain) to the region as a whole. Figure 3-6 shows the total annual generation cost under each case. In all but the long term (the year 2014 in this case[34]) the nodal market structure results in a lower cost of production (fuel, variable O&M, and environmental permit/credit costs) to serve the demand than does the zonal market structure.

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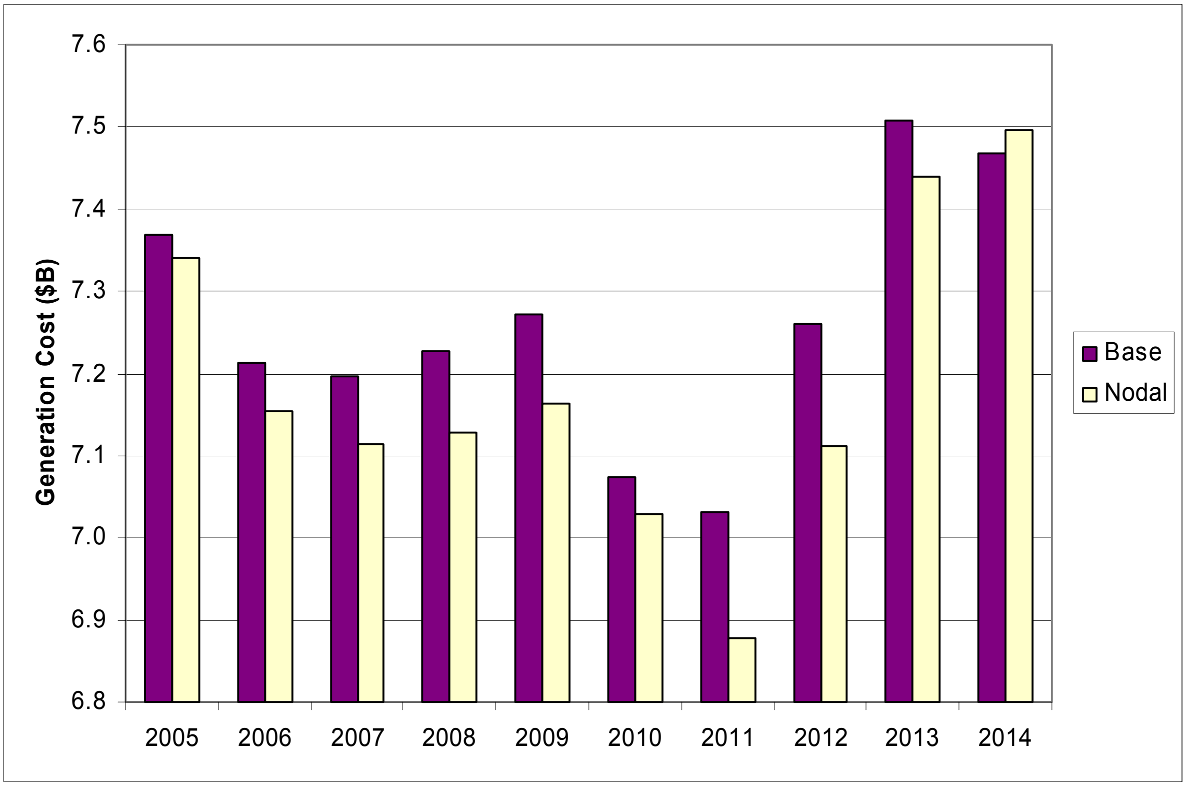
[34] Note for 2014, the lack of transmission additions in the out years requires TCA's ultimate generation additions to deviate from those called for by the original siting strategy, and thus produces simulation results that are inconsistent with the pattern of the prior study years.

Figure 3-6 Annual Generation Cost



Any assessment of differentials in generation costs between two scenarios should be placed in the context of background changes evolving over time but identical in both scenarios (near-term consideration) and changes that were caused by different market structures (e.g., new generation additions) that made the two scenarios differ economically and physically (mid-term and long-term considerations).

In the near-term we observe the same trend in both scenarios—reduction in generation costs in 2006 compared to 2005 and then growth in these costs from 2006 to 2008. That trend is accompanied, however, by an increasing gap in generation costs between Base and Change cases. This demonstrates that the nodal system is more efficient in managing congestion than the zonal system resulting in lower generation costs; it also appears to demonstrate that the Change Case-to-Base Case efficiency gap increases over time. It is important to note that the latter conclusion is more likely a modeling artifact than a reflection of the real trend: while assuming changes in transmission system by using a new load flow case in each year 2005–2009, both the definition and limits imposed on CSCs remain unchanged. Thus, congestion limits imposed on generation dispatch under the Base Case could be restrictive relative to what the system would experience if CSC limits could be relaxed with the transmission system upgrades, resulting in an overestimate of generation costs.

On average, in the near-term, generation costs savings attributed to the Change Case scenario are $67 million per year.

In the mid-term (2009–2011), generation costs decline sharply in both scenarios due to a large addition of generating capacity in 2010 and 2011 with lower marginal costs[35] under both scenarios. In these three years, the difference in generation costs between the two cases is $109 million in 2009, $46 million in 2010, and $152 million in 2011 (or $102 million per year on average). This average generation costs difference is significantly larger than the same indicator in the near-term. This is because the latter years of the study horizon are impacted also by the siting decisions that differ between the two cases. In these years, in addition to the benefits of a more efficient spot market congestion management system, siting can also be guided by the price signals of the nodal market. (This is discussed further in Sections 3.2.6 and 3.3.2.9). In this sense, the first part of the study horizon acts as a form of "sensitivity analysis" on the study, reflecting potential benefits when the generation bases are the same between the two scenarios (2005–2008). From 2009 on, results include the effects of siting decision differences between the two cases.

The mid-term trend continues for another year (2012), but is reversed in 2013 and 2014 due to difficulties associated with the modeling of further capacity expansion decisions in the absence of transmission upgrades.

Table 3-4 ERCOT System Generation Costs, shows the resulting numerical difference in millions of dollars for each year. (Note that net present values are calculated using an 8% interest rate and a 3% inflation rate.)

Table 3-4 ERCOT System Generation Costs Differences (Nodal – Zonal)

Year	Generation Cost Reduction ($M)	Generation Cost Reduction Relative to Base Case Generation($/MWh)	Percentage of Generation Cost Reduction Relatively to Base Case
2005	27.3	0.08	0.19%
2006	58.6	0.17	0.42%
2007	81.6	0.23	0.60%
2008	99.5	0.27	0.73%
2009	109.4	0.29	0.84%
2010	46.4	0.12	0.36%
2011	152.0	0.39	1.17%
2012	147.8	0.37	1.07%
2013	68.1	0.17	0.47%
2014	(28.1)	(0.07)	-0.19%
Total	762.7	—	—
Average	76.3	0.20	—
NPV	586.6	—	—

The next sections detail the cost impacts to generators and to loads respectively.

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[35] Namely, coal-fired generation.

3.3.2.3 Generators Revenues

This section presents the impacts to the generators' revenues, both gross revenue and revenue net of costs. Table 3-5 and Table 3-6 contain the cost data for the Base Case and Zonal Case simulations, respectively. For each year the total payments to the generators are shown, including:

- Payments for the market energy to the Generators at either the MCPE (Zonal Case) or Nodal Price (Change Case);
- Payments for OOME—applicable only to the Base Case;
- Payments for Uplift—an amount determined by GE-MAPS to reflect any unrecovered commitment costs for the generators;[36]
- Total Payments—the sum of the above.

For each year the Generators' Net Revenues are also reported, representing the total revenues net of variable costs (fuel, O&M, and environmental costs) and commitment-related costs such as start-up and minimum run costs. Finally, net revenues are shown on a per-MWh basis.

Table 3-5 Generators' Revenues—Base Case

	Generator Revenues ($B)				Generators Net Revenues ($B)	Generators Net Revenues ($/MWh)
Year	Energy	OOME	Uplift	Total	Rev – Cost	(Rev – Cost)/Gen
2005	14.21	0.44	0.07	14.72	7.35	21.61
2006	13.53	0.37	0.06	13.96	6.75	19.35
2007	13.30	0.31	0.06	13.67	6.48	18.13
2008	13.24	0.30	0.06	13.60	6.37	17.40
2009	12.73	0.29	0.06	13.08	5.81	15.50
2010	12.62	0.30	0.06	12.98	5.91	15.41
2011	12.44	0.45	0.06	12.95	5.92	15.12
2012	13.15	0.55	0.07	13.77	6.51	16.26
2013	13.87	0.67	0.08	14.61	7.11	17.40
2014	13.78	0.78	0.09	14.65	7.19	17.24

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[36] In the simulations there is no self-commitment per se. Rather GE-MAPS performs a Security Constrained Unit Commitment process. Any costs that are not recovered through the energy market are identified in this category of uplifted costs and include costs for minimum run times and start-up costs. This category of costs has a literal analogy under the RUC or an integrated market. They have no direct analogous set of payments under the zonal market. However, especially in light of the fact that the simulations did not capture the costs of OOMC, it is not inappropriate to measure these uplift costs in the zonal case.

3.3.2.3.1 Generators' Revenues—Nodal Case

Table 3-6 Generation Revenues—Nodal Case

	Generator Revenues ($B)				Generators Net Revenues ($B)	Generators Net Revenues ($/MWh)
Year	**Energy**	**OOME**	**Uplift**	**Total**	**Rev – Cost**	**(Rev – Cost)/Gen**
2005	13.74	0.00	0.13	13.87	6.53	19.20
2006	13.00	0.00	0.11	13.12	5.96	17.11
2007	12.64	0.00	0.11	12.75	5.63	15.81
2008	12.46	0.00	0.11	12.57	5.44	14.91
2009	12.45	0.00	0.09	12.54	5.38	14.40
2010	12.31	0.00	0.09	12.40	5.37	14.06
2011	12.17	0.00	0.09	12.26	5.38	13.77
2012	12.66	0.00	0.10	12.76	5.65	14.14
2013	13.24	0.00	0.12	13.37	5.93	14.53
2014	13.65	0.00	0.13	13.78	6.28	15.09

Note that the trends shown in Table 3-5 and Table 3-6 individually reflect forecasted fuel prices, transmission upgrades, planned resource additions, and the ultimate load growth that supports and requires additional resource additions.

In the sense of the Cost and Benefits, Table 3-7 Generators' Revenues—Delta (Nodal – Base), shows the impacts of the different market designs. The table shows a reduction in Generators' net revenues of from $400 million to $1100 million per year, equating to a reduction of between $1.14/MWh and $2.89/MWh. This decrease in net revenues can be attributed to two major factors: (1) a reduction in energy payments—locational market prices are more "selective" than zonal prices (generators that are constrained down will not be paid zonal price but rather locational price, which is smaller); and (2) the elimination of OOME which is not applicable in the nodal market. This decrease is slightly offset by an increase in uplift (non-OOME) payments and by a reduction in generation costs.[37]

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[37] The uplift payments in the Base Case are significantly lower than under the Change Case. This is because, under the Change Case, the potential need for uplift occurs each hour when the unit operates at a cost exceeding the market-clearing price for that unit. Under the Base Case, under similar circumstances, the unit will be collecting OOME payments. The need for an uplift will only exist for generating units that were scheduled to run below cost on the zonal basis and were not used to resolve local congestion (and hence earned no OOME payments).

Table 3-7 Generators' Revenues—Delta (Nodal – Base)

	Generator Revenues ($M)				Generators Net Revenues ($M)	Generators Net Revenues ($ MWh)	Percentage of Generators Net Revenue Delta Relatively to Base Case
Year	**Energy**	**OOME**	**Uplift**	**Total**	**Rev - Cost**	**(Rev - Cost)/Gen Base**	**(Rev - Cost)/GenCost BaseCase**
2005	(472.7)	(441.6)	65.1	(849.2)	(821.8)	(2.41)	-5.58%
2006	(521.0)	(374.8)	50.7	(845.0)	(786.5)	(2.26)	-5.63%
2007	(661.0)	(309.3)	47.0	(923.2)	(841.6)	(2.36)	-6.16%
2008	(776.3)	(300.9)	49.3	(1027.9)	(928.4)	(2.54)	-6.83%
2009	(280.6)	(287.8)	32.8	(535.6)	(426.2)	(1.14)	-3.26%
2010	(306.4)	(302.2)	27.9	(580.7)	(534.3)	(1.39)	-4.12%
2011	(273.8)	(447.1)	28.8	(692.1)	(540.2)	(1.38)	-4.17%
2012	(487.8)	(551.7)	34.7	(1004.8)	(857.0)	(2.14)	-6.23%
2013	(623.7)	(667.9)	44.3	(1247.4)	(1179.3)	(2.89)	-8.07%
2014	(133.4)	(781.7)	42.0	(873.1)	(901.2)	(2.16)	-6.15%
Total	(4536.8)	(4465.0)	422.6	(8579.2)	(7816.5)	—	—
Average	(453.7)	(446.5)	42.3	(857.9)	(781.6)	(2.1)	—
NPV	(3589.6)	(3327.9)	334.0	(6583.5)	(5996.9)	—	—

3.3.2.4 Out-of- Merit Order Energy Payment Details

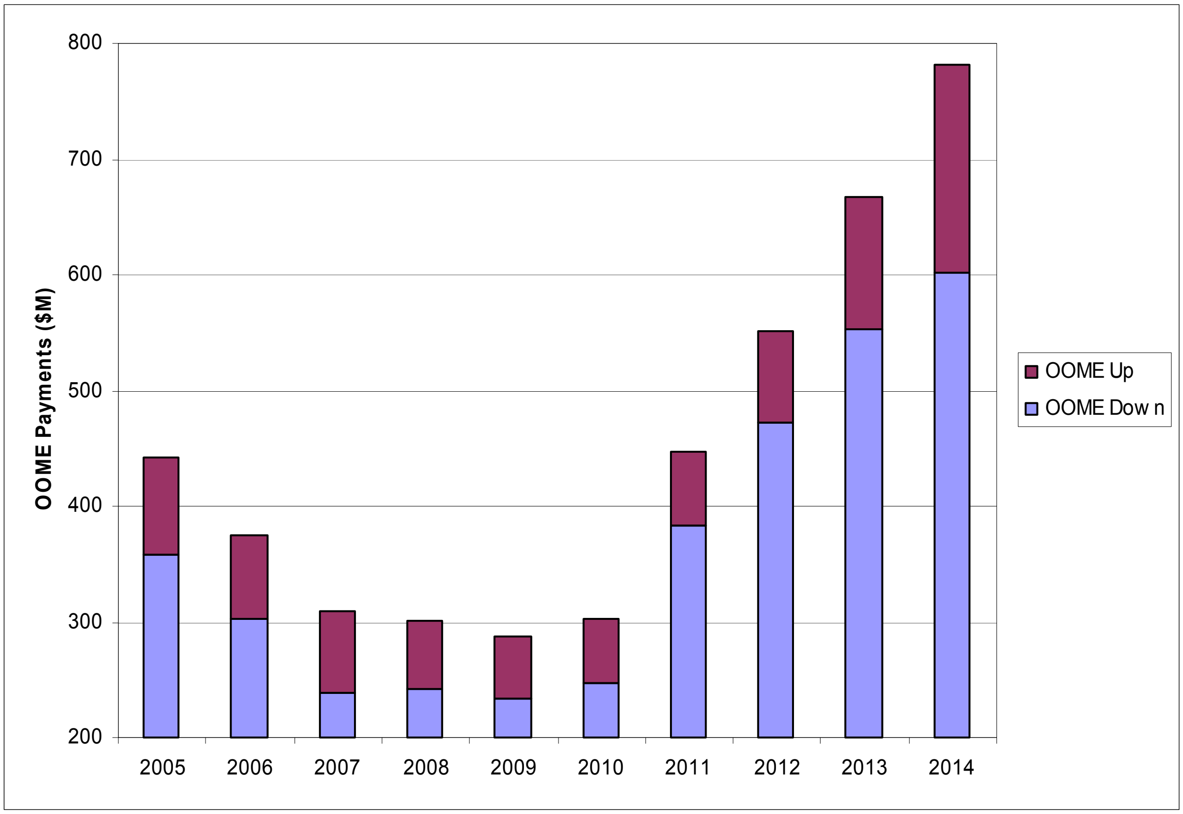
This section presents data and discussion of the OOME simulated payments in the Base Case model. Recall that the ERCOT system uses a three-Step method to resolve zonal and local congestion:

- Step 1: ERCOT balances generation and loads using zonal representation. Only inter-zonal congestion is addressed.
- Step 2: ERCOT resolves local intra-zonal congestion by moving up or down generators that could efficiently resolve local congestion.
- Step 3: ERCOT rebalances generation and loads using zonal representation *subject to generators moved up or down* at Step 2.

MCPEs are determined at Step 3.Generators moved up or down at Step 2 are paid OOME for the difference between the Step 1 dispatch and the Step 2 dispatch.

The EIA simulated these outcomes for the Base Case model and calculated hourly OOME payments. Figure 3-7 shows the annual simulated OOME payments to all generators in the ERCOT region.

Figure 3-7 OOME Annual Payments ($M)



The figure shows that OOME Down payments are significantly higher than OOME Up payments in some years (especially years in which the simulation had significant intrazonal congestion). An illustrative example explains why this is the case, given the nature of OOME payments. Assume that a zonal price is $50/MWh. Assume that to resolve local congestion a coal unit must be ramped down by 100 MW, and a peaker must be ramped up by 100 MW. Further, assume the following prices:

- Coal unit's cost is $15/MWh
- Peaker's cost is $60/MWh

Given the payment policies, the coal unit will be paid OOME Down:

- ($50 – $15) × 100 MW = $3500

The peaker will be paid OOME Up

- ($60 – $50) × 100 MW = $1000

Thus, because of the cost structures of the types of units moving down vs. those moving up, OOME down tends to be greater than OOME up.

Table 3-8 shows the breakdown of simulated OOME Up and OOME Down payments by resource type for the study horizon.

Table 3-8 OOME Up and Down—2005

Type	OOME Up ($M)	OOME Down ($M)
GT	6.36	12.90
CC	31.40	112.96
STg	45.04	13.73
STc	0.27	197.28
Other	0.17	21.51
Total	83.24	358.37

The estimated OOME payments for 2005 shown in the table are significantly higher than recent actual OOME payments in ERCOT. For example, OOME payments in 2002 and 2003 were $61 million and $108 million, respectively.[38] During the first nine months of 2004, OOME payments were $62 million. It is important to note, however, that the estimated $442 million in OOME payments include *all* costs of managing local congestion both in terms of the depth at which transmission system is considered and the scope of resources used to manage congestion. Thus, simulated OOME payments include the costs of resolving local congestion on all transmission elements including the 69-kV system, which is not monitored by ERCOT and therefore not addressed through actual OOME payments. At the same time, ERCOT relies on Reliability Must Run (RMR) units to resolve local congestion. Payments ERCOT makes to RMR units are not included in OOME. TCA, in contrast, models RMR units as dispatchable and OOME payments made to these units are part of the total OOME. TCA believes that a more relevant point of comparison would be the Total Local Congestion cost payments reported by ERCOT, which in 2002 accounted for $225 million and in 2003—for $401 million. These numbers are of comparable magnitude to TCA estimates. It is also interesting to note that in 2003, the ratio of OOME Up to OOME down was 3.3 and that during the first nine months of 2004, that ratio was 6.0. For comparison, TCA estimated for 2005 a ratio of 4.3, which is within the range of the ERCOT actual 2003 and 2004 ratios. In sum, it appears that the assessment of the structure and the magnitude of OOME payments based on TCA simulations is reasonable.

3.3.2.5 Load Impacts

This Section addresses the Load impacts of the Change Case. Loads are impacted primarily through the changing energy prices and through the elimination of OOME payments. Results are characterized in terms of Demand, which is equal to loads plus net exports. While the impacts to exports are not viewed as significant, net exports are included to ensure consistent and comprehensive comparisons.

Table 3-9 and Table 3-10 show the payments by loads for each of the study years for the Base and Change Cases respectively.

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[38] http://www.ercot.com/Participants/PublicMarketInfo/OOMC_LCEnergyPayments-4.xls. Also note, however that these OOM payments include capacity OOM payments (OOMC payments). TCA did not measure OOMC payments separate from unrecovered commitment costs reported as “uplift”. Thus any comparison of actual costs relative to simulated costs other than a general “order-of-magnitude” check of total costs of managing local congestion is not particularly meaningful.

Table 3-9 Cost of Serving Demand—Base Case

	Cost of Serving Demand ($B)				Total Cost Of Serving Demand ($/MWh)
Year	Energy (Loads)	Uplift and OOME (Loads)	Total	Export	Total Cost/Total Load Base Case
2005	14.37	0.51	14.88	0.08	43.75
2006	13.67	0.44	14.10	0.07	40.46
2007	13.45	0.37	13.82	0.07	38.71
2008	13.39	0.36	13.75	0.06	37.57
2009	12.85	0.35	13.20	0.06	35.24
2010	12.68	0.36	13.04	0.06	34.07
2011	12.50	0.51	13.01	0.06	33.23
2012	13.20	0.62	13.82	0.06	34.54
2013	13.94	0.75	14.69	0.06	35.95
2014	13.93	0.87	14.80	0.06	35.48

Table 3-10 Cost of Serving Demand—Nodal Case

	Cost of Serving Demand ($B)				Total Cost Of Serving Demand ($/MWh)
Year	Energy (Loads)	Uplift and OOME (Loads)	Total	Export	Total Cost/Total Load Nodal Case
2005	14.38	0.13	14.51	0.07	42.67
2006	13.54	0.11	13.66	0.07	39.18
2007	13.15	0.11	13.26	0.06	37.14
2008	12.93	0.11	13.04	0.06	35.63
2009	12.79	0.09	12.89	0.06	34.41
2010	12.76	0.09	12.84	0.06	33.54
2011	12.70	0.09	12.79	0.06	32.67
2012	13.42	0.10	13.52	0.06	33.80
2013	14.46	0.12	14.58	0.06	35.68
2014	14.99	0.13	15.12	0.06	36.26

Table 3-11 shows the difference in the load impacts between the Nodal Case and the Base Case. As a result of the market redesign, loads' cost of served energy decreases by hundreds of millions of dollars. In the near-term, this benefit comes from two major sources: (1) Reduction in energy costs (load times price) and (2) Elimination of the OOME payment. In the mid- and long-term, this benefit comes only from the elimination of the OOME payment, which is offset by an increase in energy costs in all years except 2014. This estimated impact does not reflect congestion rent refund, which is discussed in more detail below.

Table 3-11 Cost of Serving Demand—Delta (Nodal – Base)

	Cost of Serving Demand ($M)				Total Cost of Serving Demand ($M)	Total Cost Of Serving Demand ($/MWh)	Percentage of Cost of Serving Demand Delta Relatively to Base Case
Year	**Energy (Loads)**	**Uplift and OOME (Loads)**	**Total**	**Export**		**Total Delta/Total Load Base case**	**Total Delta/Cost Base Case**
2005	**8.72**	**(376.51)**	**(367.79)**	**(2.50)**	**(370.29)**	**(1.08)**	**-2.47%**
2006	**(123.72)**	**(324.09)**	**(447.81)**	**(2.13)**	**(449.94)**	**(1.28)**	**-3.18%**
2007	**(296.79)**	**(262.23)**	**(559.02)**	**(2.35)**	**(561.37)**	**(1.57)**	**-4.05%**
2008	**(460.09)**	**(251.58)**	**(711.67)**	**(3.04)**	**(714.70)**	**(1.94)**	**-5.18%**
2009	**(53.22)**	**(254.97)**	**(308.20)**	**(3.26)**	**(311.45)**	**(0.82)**	**-2.34%**
2010	**73.26**	**(274.29)**	**(201.02)**	**(3.51)**	**(204.53)**	**(0.52)**	**-1.54%**
2011	**199.79**	**(418.34)**	**(218.55)**	**(3.21)**	**(221.76)**	**(0.56)**	**-1.68%**
2012	**224.07**	**(517.03)**	**(292.96)**	**(3.21)**	**(296.17)**	**(0.73)**	**-2.12%**
2013	**512.71**	**(623.63)**	**(110.92)**	**(2.15)**	**(113.07)**	**(0.27)**	**-0.76%**
2014	**1065.12**	**(739.72)**	**325.40**	**0.13**	**325.53**	**0.78**	**2.20%**
Total	**1149.85**	**(4042.39)**	**(2892.53)**	**(25.22)**	**(2917.75)**	**—**	**—**
Average	**114.99**	**(404.24)**	**(289.25)**	**(2.52)**	**(291.77)**	**(0.80)**	**—**
NPV	**552.20**	**(2993.87)**	**(2441.67)**	**(19.77)**	**(2461.43)**	**—**	**—**

3.3.2.5.1 Congestion Rent and Load Impacts Reflecting Congestion Rent Refunds

The above impacts to loads reflect only the impact with respect to the cost of the energy. However, ERCOT market rules allow for the refund of excess congestion payments, referred to as "congestion rent," collected by ERCOT. Given that these congestion rents also change between the Base Case and the Nodal Case, the accounting of impacts to loads is incomplete without the consideration of the distribution of the congestion rents back to loads.

Congestion Rent is generated as follows:

- ERCOT collects money from loads (cost of served load, based on the MCPE or the nodal price times the MW quantity of energy serving load)
- ERCOT makes payments to generators (generators' revenues)
- ERCOT generally collects more from loads than is needed to pay generators, given the fact that flows over constrained interfaces are charged their marginal price rather than only the actual cost to manage the amount of flow exceeding the interface capacity
- The difference between what is collected from the loads and what is paid to the generators is the congestion rent

In the zonal market, congestion rent is the cost of managing inter-zonal congestion only, whereas the cost of managing intra-zonal congestion is OOME. In the nodal market, congestion rent is the cost of managing both inter-zonal and intra-zonal congestion

In the EIA, congestion rent is distributed back to the loads based on ERCOT load share. This is consistent with the ERCOT rules for distribution of such excess funds and was how ERCOT operated, for example, in the first year of operation. Note that with the additional financial mechanism of Transmission Congestion Rights (TCRs) or Congestion Revenue Rights (CRRs), the distribution of congestion rent is slightly different. In this case congestion rent goes first as payments to TCR or CRR holders, and any excess congestion rent after such payments is refunded to loads. TCRs and CRRs are generally obtained through the auction where holders pay a clearing price for the funds. The auction proceeds are paid to loads based on ERCOT load share. In an efficient TCR/CRR market, TCR/CRR holders are expected to pay in the auction amounts equal to the expected value of the congestion rent payments, though this may be adjusted slightly by the value of the risk premium. Thus, with or without the TCR/CRR market, the payments to loads given the collection of congestion rent are expected to be essentially equivalent.[39]

It is also important to note that the congestion rent refund under current ERCOT proposals is based on load share over the entire ERCOT region. This means that there can be a cost shift associated with any changes in the congestion patterns between the two cases. For example, if one zone—the North zone, for example—experiences significant local congestion in the nodal case then loads in the North will pay higher nodal prices to cover the cost of the congestion, but the congestion rent associated with those payments will be refunded to loads across ERCOT. Load impacts on a regional basis are presented in Section 3.3.2.6.

Figure 3-8 Congestion Rent: Base vs. Nodal shows the magnitude of the congestion rent in each of the simulated years in the Base and Nodal Cases. Note that the congestion rent in the Nodal Case is significantly higher than in the Base. In the Base case congestion rent accrues only for the CSCs. Since local constraints are managed based on their actual cost to redispatch, rather than being priced marginally, no congestion rent accrues as a result of these constraints. In the Nodal Case, however, the management of any congested interface can create congestion rent, and as a result the Nodal Case congestion rent is significantly higher.

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[39] To the extent that the TCR/CRR market is inefficient, TCR/CRR holders would pay more or less than the expected value of the congestion rents. In this case, to the extent that the TCR/CRR holders were not load-serving entities themselves, the actual refund of the congestion rent value through the TCR/CRR process would be more or less than the allocation represented in this study.

Figure 3-8 Congestion Rent: Base vs. Nodal

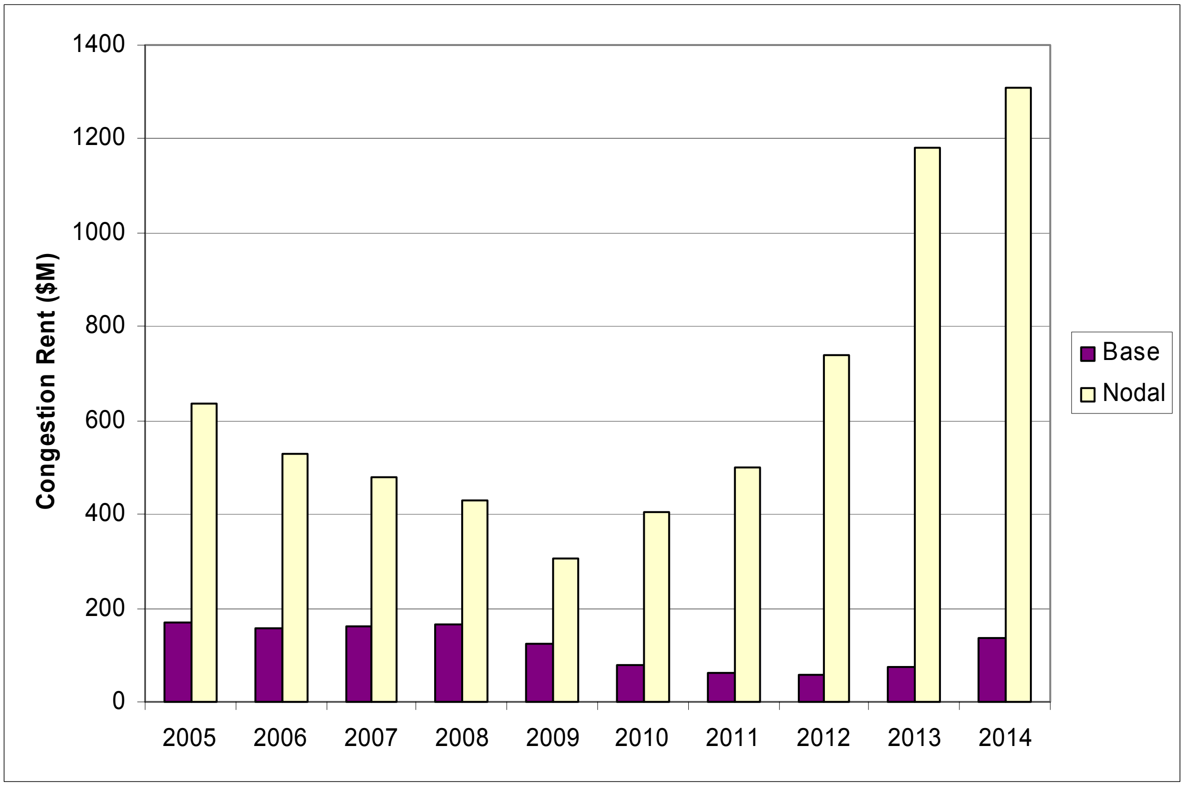


Table 3-12 through Table 3-14 show the cost to serve Load when the allocation of congestion rent back to the loads is considered. Table 3-12 shows the impacts in the Base case, Table 3-13 shows the results for the Nodal Case, and Table 3-14 shows the difference.

Table 3-12 Cost of Serving Demand Revisited—Base Case

	Cost of Serving Demand Revisited ($B)			Cost of Serving Demand after Congestion Rent Refund ($/MWh)
Year	Cost of Serving Demand before Congestion Rent	Congestion Rent Refund	Cost of Serving Demand after Congestion Rent Refund	
2005	14.88	0.17	14.71	43.25
2006	14.10	0.16	13.95	40.02
2007	13.82	0.16	13.66	38.26
2008	13.75	0.16	13.59	37.13
2009	13.20	0.13	13.07	34.90
2010	13.04	0.08	12.97	33.86
2011	13.01	0.06	12.95	33.07
2012	13.82	0.06	13.76	34.39
2013	14.69	0.07	14.62	35.77
2014	14.80	0.13	14.66	35.16

Table 3-13 Cost of Serving Demand Revisited—Nodal Case

	Cost of Serving Demand Revisited ($B)			Cost of Serving Demand after Congestion Rent Refund ($/MWh)
Year	Cost of Serving Demand before Congestion Rent	Congestion Rent Refund	Cost of Serving Demand after Congestion Rent Refund	
2005	14.51	0.63	13.88	40.80
2006	13.66	0.53	13.13	37.67
2007	13.26	0.48	12.78	35.80
2008	13.04	0.43	12.61	34.46
2009	12.89	0.31	12.58	33.60
2010	12.84	0.41	12.44	32.48
2011	12.79	0.50	12.29	31.40
2012	13.52	0.74	12.78	31.95
2013	14.58	1.18	13.40	32.79
2014	15.12	1.31	13.82	33.12

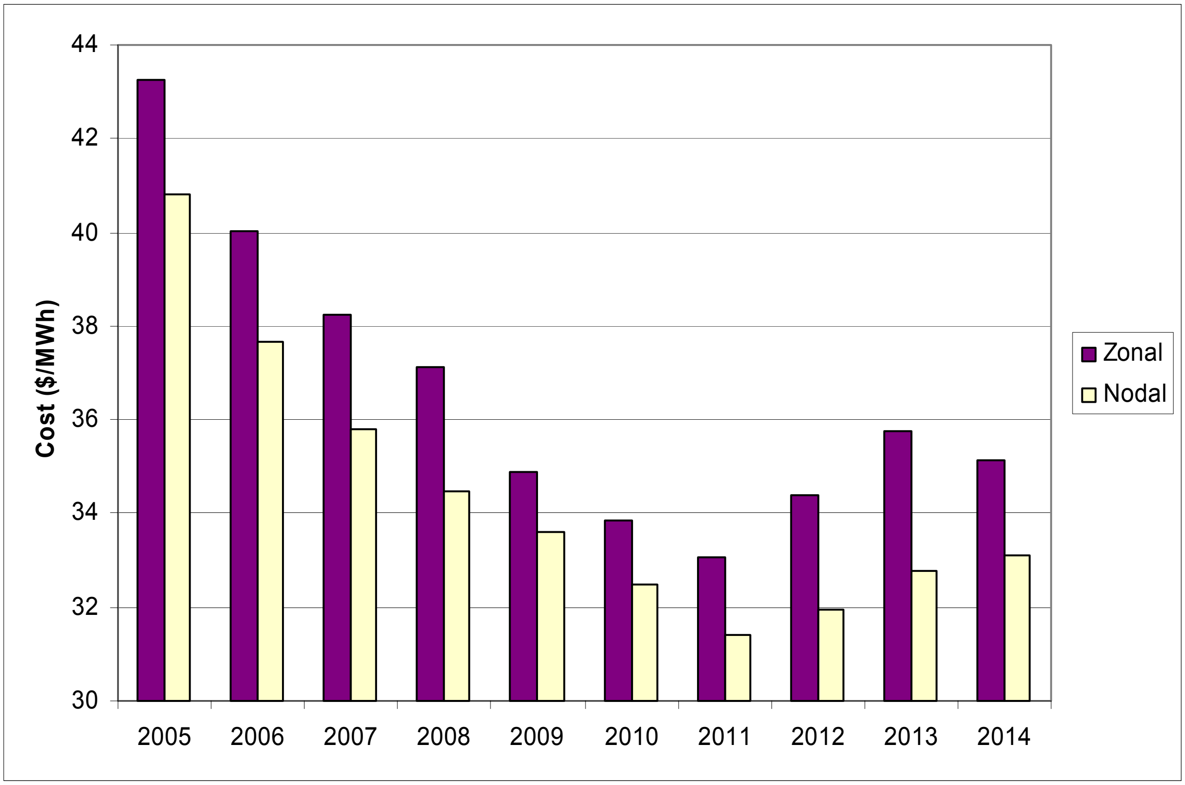
Table 3-14 shows the cost to serve demand difference between the Nodal and Base Cases, reflecting an average difference in costs to loads in ERCOT of $2.18/MWh. This represents approximately a 6% reduction of cost to serve the load, and reflects a net impact (NPV) of $6.3 billion over the 10 years.

Table 3-14 Cost of Serving Demand Revisited—Delta (Nodal – Base)

	Cost of Serving Demand Revisited ($M)			Cost of Serving Demand after Congestion Rent Refund ($/MWh)	Percentage of Cost Delta Relatively to Base Case
Year	Cost of Serving Demand before Congestion Rent	Congestion Rent Refund	Cost of Serving Demand after Congestion Rent Refund		
2005	(367.79)	464.49	(832.28)	(2.45)	-5.66%
2006	(447.81)	372.77	(820.57)	(2.35)	-5.88%
2007	(559.02)	319.99	(879.01)	(2.46)	-6.44%
2008	(711.67)	265.49	(977.16)	(2.67)	-7.19%
2009	(308.20)	180.53	(488.73)	(1.30)	-3.74%
2010	(201.02)	328.70	(529.73)	(1.38)	-4.08%
2011	(218.55)	436.85	(655.40)	(1.67)	-5.06%
2012	(292.96)	682.26	(975.23)	(2.44)	-7.09%
2013	(110.92)	1,107.60	(1,218.53)	(2.98)	-8.34%
2014	325.40	1,174.91	(849.51)	(2.04)	-5.79%
Total	(2,892.53)	5,333.61	(8,226.14)	—	—
Average	(289.25)	533.36	(822.61)	(2.18)	—
NPV	(2,441.67)	3,869.57	(6,311.23)	—	—

Figure 3-9 shows the total cost of serving demand, with the congestion rent refund effect, for each of the cases over the study horizon.

Figure 3-9 Cost of Serving Demand Revisited—Base vs. Nodal



3.3.2.5.2 Summary of Load Impact Components

Figure 3-10 and Figure 3-11 show the elements of the charges the loads are paying in the Zonal (Base) and Nodal Cases. Note that while the energy payment alone (inner, light blue bar) is sometimes higher in the Nodal Case, as indicated in Table 3-11 Cost of Serving Demand—Delta (Nodal – Base), when OOME costs are considered, the cost to serve load in the Nodal Case is lower in each year. Further, when the congestion rent refund (top section of each bar—green area) is incorporated into the analysis, as discussed in the previous section, the graphs show a significantly lower cost (lower section of major bar in dark blue, the "Cost after CR").

Figure 3-10 Total Cost Components for the Zonal Case including Congestion Rent (CR)

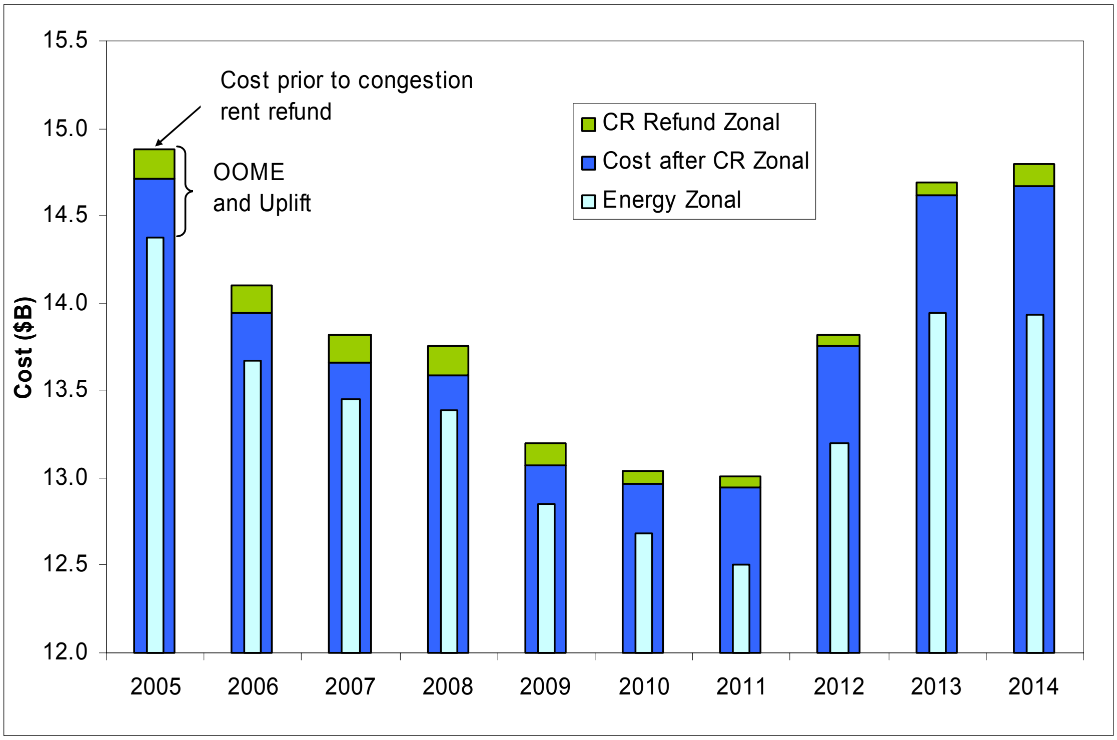
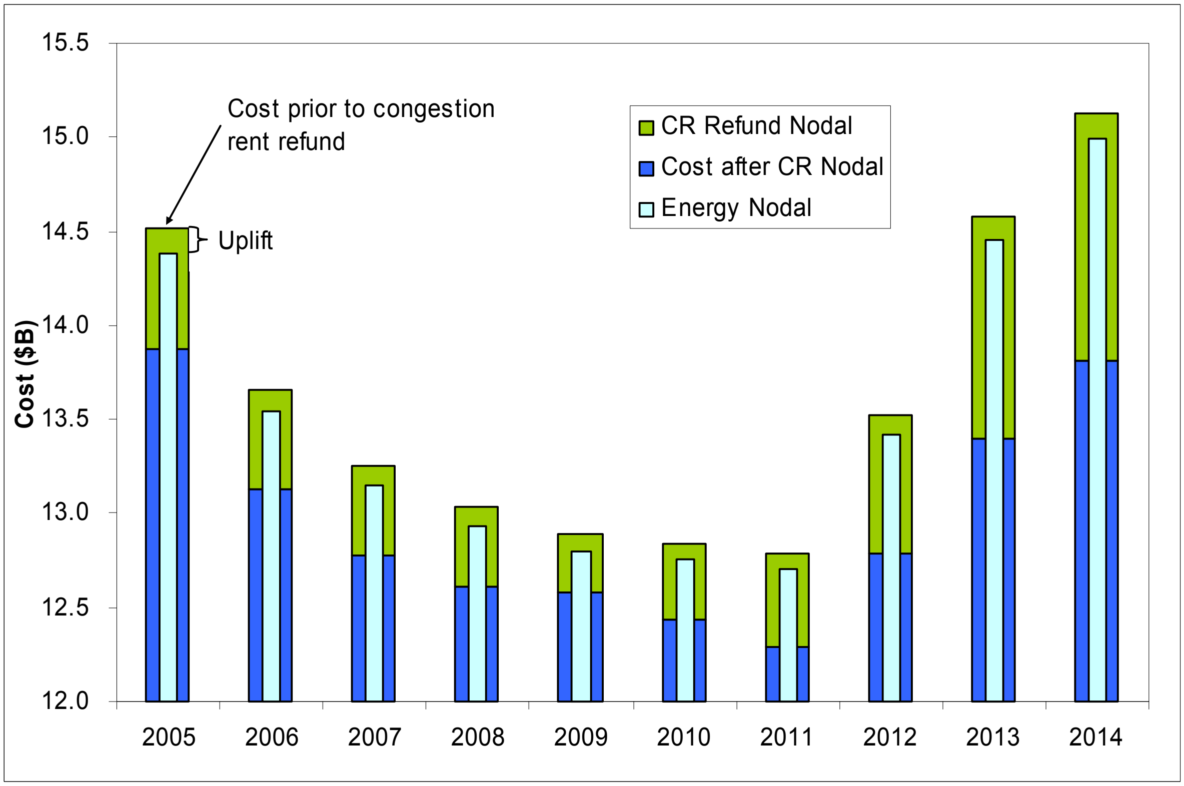


Figure 3-11 Total Cost Components for the Nodal Case including Congestion Rent (CR)



3.3.2.6 REGIONAL ANALYSIS (BY ZONE)

This section presents the results of the EIA with respect to each of the zones: Houston, North, Northeast, South, and West. Generation impacts are discussed first, then load impacts are discussed. The generation impacts were determined by grouping generating plants by zone and then summarizing the respective impacts of each zone's generating plants. The load impacts were determined by mapping load busses to zones and calculating the net impacts to the load corresponding to each zone's loads. Note that while LMP price impacts Metropolitan areas are reported in Section 3.3.2.8, the regional analysis includes in the impacts of all generators or all load busses located within each load area, including any which may otherwise belong to a NOIE load zone.

3.3.2.6.1 Regional Generation Impacts

Table 3-15 and Table 3-16 show the generation net margin impacts by zone by year as total dollar value and as $/MWh, respectively. The tables show that generators in the Houston zone experience the greatest decrease in net revenues, representing nearly 90% of the ERCOT total decrease in net revenues. Generators in the North also have a significant decrease in net revenues. Generators in the West experience a less severe decrease in net revenue. Generators in the Northeast and South zones see a net increase.

In the near term (2005–2008), the impact on generators in Houston and in the South is largely driven by the significant decline in market prices in Houston anticipated with the introduction of the nodal market and by a much smaller price increase in the South zone. For example, the Houston zonal price in 2005 is estimated at $45.8/MWh on average over all hours. For comparison, average of all LMPs in the Houston Zone in 2005 is estimated at $40.4/MWh on average over all hours. In contrast, prices for the same period in the South Zone will increase from $37.9/MWh under the Base Case to $40.0/MWh under the Change Case. This decline in prices in Houston (and concurrent price increase in South) is driven by better *inter*-zonal congestion management achieved under the Change Case scenario when deployment of generating units required to resolve inter-zonal congestion is based on actual, not average, shift factors. As a result, a different dispatch of generating units in the Houston and South zones under the Change Case scenario allows the resolution of the congestion on the South-Houston CSC and the reduction of prices in Houston. With lower prices under the Change Case scenario, generation in Houston will decline compared to the Base Case scenario. In the South Zone, in contrast, generation will increase. In sum, generators in Houston will see lower net revenues whereas generators in the South Zone will see higher revenues. This trend will continue over the mid-term and mostly in the long-term, although over that period it is influenced not only by prices but also by big differences in capacity additions between scenarios.

The decline in net revenues to generators in the North is largely driven by a decline in prices *to generators* in the north in the nodal Change case relative to the Base Case. (It is important to note that at the same time average nodal price *to loads* in the North will likely be higher than the zonal price reflecting significant congestion within the North zone). While prices to generators in the North will decline with the introduction of the nodal market, prices in the Northeast will increase reflecting higher generation in the Northeast due to the ability to export more power to the North. As a result, net revenues to generators in the Northeast will increase in all years except 2005.[40]

Under the Change Case, net revenues to generators in the West decline along with the decline of generation and prices. With improved congestion management under the Change Case scenario, the generation in the North becomes more competitive: more expensive generators in the North are displaced by importing less expensive generation from the Northeast; that, in turn, reduces the need for imports from the West to the North, and depresses prices and drives down revenues to generators in the West.

Table 3-15 Net Impact on Generator' Margin ($M Nodal – Base)

	Net Impact on Generator's Margin Nodal – Base ($M)					
Year	**Houston**	**North**	**Northeast**	**South**	**West**	**Total**
2005	(651)	(192)	(31)	76	(24)	(822)
2006	(665)	(184)	11	78	(27)	(786)
2007	(752)	(164)	18	82	(25)	(842)
2008	(810)	(156)	19	50	(32)	(928)
2009	(345)	(149)	32	71	(36)	(426)
2010	(580)	(74)	35	119	(36)	(534)
2011	(683)	(46)	31	189	(33)	(540)
2012	(684)	(178)	13	26	(34)	(857)
2013	(811)	(163)	23	(205)	(24)	(1,179)
2014	(974)	8	32	(39)	72	(901)
Total	**(6,953)**	**(1,297)**	**184**	**449**	**(199)**	**(7,816)**
Average	**(695)**	**(130)**	**18**	**45**	**(20)**	**(782)**
NPV	**(5,310)**	**(1,044)**	**129**	**397**	**(168)**	**(5,997)**

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[40] In 2005, simulation results show almost no increase in generation and therefore export from Northeast to North. It is likely that the increase in the export capability becomes possible with new transmission upgrades effective only in 2006.

Table 3-16 Net Impact on Generators' Margin ($/MWh Nodal – Base)

	Net Impact on Generator's Margin Relatively to Base [Case Nodal – Base]/Total Generation ($/MWh)					
Year	**Houston**	**North**	**Northeast**	**South**	**West**	**Total**
2005	**(6.93)**	**(1.90)**	**(1.30)**	**0.74**	**(1.30)**	**(2.41)**
2006	**(6.82)**	**(1.77)**	**0.51**	**0.74**	**(1.41)**	**(2.26)**
2007	**(7.59)**	**(1.53)**	**0.82**	**0.76**	**(1.22)**	**(2.36)**
2008	**(8.07)**	**(1.41)**	**0.78**	**0.46**	**(1.52)**	**(2.54)**
2009	**(3.38)**	**(1.28)**	**1.31**	**0.65**	**(1.65)**	**(1.14)**
2010	**(5.07)**	**(0.64)**	**1.49**	**1.11**	**(1.64)**	**(1.39)**
2011	**(6.13)**	**(0.39)**	**1.32**	**1.61**	**(1.45)**	**(1.38)**
2012	**(6.08)**	**(1.47)**	**0.56**	**0.22**	**(1.63)**	**(2.14)**
2013	**(7.15)**	**(1.34)**	**0.99**	**(1.59)**	**(1.13)**	**(2.89)**
2014	**(8.51)**	**0.07**	**1.38**	**(0.28)**	**3.42**	**(2.16)**
Average	**(6.57)**	**(1.16)**	**0.79**	**0.44**	**(0.95)**	**(2.07)**

3.3.2.6.2 Load Impacts

Table 3-17 and Table 3-18 show the load impacts by region on a dollar basis and $/MWh basis respectively prior to the application of congestion rent refunds. The tables show that based on energy payments alone, benefits are concentrated in the Houston zone.

Table 3-17 Net Impact on Cost Served Load Before Congestion Rent Refund ($M Nodal – Base)

	Net Impact on Cost of Served Load before Congestion Rent Refund Nodal – Base ($M)					
Year	**Houston**	**North**	**Northeast**	**South**	**West**	**Total**
2005	**(739)**	**12**	**(3)**	**355**	**8**	**(368)**
2006	**(754)**	**6**	**(1)**	**292**	**9**	**(448)**
2007	**(855)**	**(28)**	**(2)**	**318**	**8**	**(559)**
2008	**(914)**	**(54)**	**(4)**	**257**	**4**	**(712)**
2009	**(381)**	**(26)**	**(3)**	**101**	**1**	**(308)**
2010	**(176)**	**(7)**	**(2)**	**(18)**	**3**	**(201)**
2011	**(81)**	**3**	**(0)**	**(136)**	**(4)**	**(219)**
2012	**(44)**	**(38)**	**(7)**	**(191)**	**(12)**	**(293)**
2013	**(133)**	**107**	**(1)**	**(89)**	**5**	**(111)**
2014	**(258)**	**230**	**7**	**315**	**31**	**325**
Total	**(4,336)**	**205**	**(16)**	**1,203**	**52**	**(2,893)**
Average	**(434)**	**21**	**(2)**	**120**	**5**	**(289)**
NPV	**(3,641)**	**109**	**(14)**	**1,064**	**39**	**(2,442)**

Table 3-18 Net Impact on Cost Served Load Before Congestion Rent Refund ($/MWh Nodal – Base)

	Net Impact on Cost of Served Load before Congestion Rent Refund Relatively to Base [Case Nodal – Base]/Total Load ($/MWh)					
Year	**Houston**	**North**	**Northeast**	**South**	**West**	**Total**
2005	**(6.86)**	**0.10**	**(0.45)**	**3.78**	**0.52**	**(1.08)**
2006	**(6.88)**	**0.05**	**(0.12)**	**3.02**	**0.58**	**(1.28)**
2007	**(7.68)**	**(0.23)**	**(0.29)**	**3.17**	**0.50**	**(1.57)**
2008	**(8.11)**	**(0.43)**	**(0.53)**	**2.48**	**0.21**	**(1.94)**
2009	**(3.33)**	**(0.20)**	**(0.41)**	**0.95**	**0.03**	**(0.82)**
2010	**(1.52)**	**(0.06)**	**(0.30)**	**(0.16)**	**0.16**	**(0.52)**
2011	**(0.69)**	**0.02**	**(0.00)**	**(1.20)**	**(0.24)**	**(0.56)**
2012	**(0.37)**	**(0.28)**	**(0.86)**	**(1.64)**	**(0.64)**	**(0.73)**
2013	**(1.10)**	**0.77**	**(0.09)**	**(0.74)**	**0.25**	**(0.27)**
2014	**(2.11)**	**1.62**	**0.80**	**2.55**	**1.55**	**0.78**
Average	**(3.87)**	**0.14**	**(0.23)**	**1.22**	**0.29**	**(0.80)**

Table 3-19 and Table 3-20 show the load impacts by region on a dollar basis and $/MWh basis respectively when congestion rent impacts are incorporated.

The net effect with congestion rent refund is that Loads in the Houston, North, Northeast, and West zones pay less to serve load with nodal in all years. However, loads in the South zone pay higher costs in the near-term but pay lower costs under the nodal market in the mid- and long-term. The major reason behind that switch in the impact on loads in the South is the difference in the capacity expansion strategies under the two scenarios. Under the Base Case, new capacity is added in the Houston zone in 2009 and 2010, whereas under the Change Case, new capacity addition in these two years takes place in the South zone. As a result, under the Change Scenario during 2009–2010 prices in the South decrease and fall below zonal prices under the Base Case scenario. This reversal in price relationship between the two scenarios is the major driver behind the impact on loads in the South zone. On a $/MWh basis, costs to load in Houston are substantially lower throughout the study period, load costs reductions in the North, Northeast, and Western zones are significant, and impacts in the Southern zone result in a net overall positive trend by the end of the study horizon, but not significantly so.

Table 3-19 Net Impact on Served Load After Congestion Rent Refund ($M Nodal – Base)

	Net Impact on Cost of Served Load after Congestion Rent Refund Nodal – Base ($M)					
Year	**Houston**	**North**	**Northeast**	**South**	**West**	**Total**
2005	**(886)**	**(148)**	**(12)**	**227**	**(13)**	**(832)**
2006	**(872)**	**(121)**	**(8)**	**188**	**(8)**	**(821)**
2007	**(955)**	**(137)**	**(9)**	**228**	**(7)**	**(879)**
2008	**(996)**	**(144)**	**(9)**	**182**	**(9)**	**(977)**
2009	**(436)**	**(88)**	**(7)**	**50**	**(8)**	**(489)**
2010	**(276)**	**(119)**	**(9)**	**(113)**	**(13)**	**(530)**
2011	**(212)**	**(146)**	**(9)**	**(263)**	**(25)**	**(655)**
2012	**(247)**	**(271)**	**(22)**	**(391)**	**(45)**	**(975)**
2013	**(460)**	**(271)**	**(24)**	**(415)**	**(48)**	**(1,219)**
2014	**(602)**	**(171)**	**(18)**	**(33)**	**(25)**	**(850)**
Total	**(5,942)**	**(1,615)**	**(127)**	**(342)**	**(199)**	**(8,226)**
Average	**(594)**	**(162)**	**(13)**	**(34)**	**(20)**	**(823)**
NPV	**(4,811)**	**(1,212)**	**(94)**	**(52)**	**(142)**	**(6,311)**

Table 3-20 Net Impact on Served Load After Congestion Rent Refund ($/MWh Nodal – Base)

	Net Impact on Cost of Served Load after Congestion Rent Refund Relatively to Base [Case Nodal – Base]/Total Load ($/MWh)					
Year	**Houston**	**North**	**Northeast**	**South**	**West**	**Total**
2005	**(8.23)**	**(1.27)**	**(1.81)**	**2.41**	**(0.85)**	**(2.45)**
2006	**(7.94)**	**(1.02)**	**(1.19)**	**1.95**	**(0.49)**	**(2.35)**
2007	**(8.58)**	**(1.13)**	**(1.19)**	**2.27**	**(0.40)**	**(2.46)**
2008	**(8.83)**	**(1.15)**	**(1.26)**	**1.75**	**(0.51)**	**(2.67)**
2009	**(3.81)**	**(0.68)**	**(0.90)**	**0.46**	**(0.45)**	**(1.30)**
2010	**(2.38)**	**(0.91)**	**(1.16)**	**(1.02)**	**(0.70)**	**(1.38)**
2011	**(1.81)**	**(1.09)**	**(1.12)**	**(2.31)**	**(1.35)**	**(1.67)**
2012	**(2.08)**	**(1.98)**	**(2.57)**	**(3.34)**	**(2.34)**	**(2.44)**
2013	**(3.81)**	**(1.94)**	**(2.80)**	**(3.45)**	**(2.47)**	**(2.98)**
2014	**(4.93)**	**(1.20)**	**(2.02)**	**(0.27)**	**(1.27)**	**(2.04)**
Average	**(9.53)**	**(1.24)**	**(1.60)**	**(0.15)**	**(1.08)**	**(2.18)**

3.3.2.7 SEGMENT ANALYSIS (BY PARTICIPANT)

This section presents the results as they pertain to particular market segments. Segments identified in this EIA are Municipalities (Munis), Cooperatives (COOPs), Investor-Owned Utility (IOU) Affiliates, and Independent Power Producers (IPPs) for generation impacts, and Affiliated Retail Energy Providers (AREPs), Independent Retail Energy Providers—not including AREPs—(IREPs), Munis and COOPs for load impacts.

Generation results are presented first, followed by load results. For the segment analysis, the numerical results are provided followed by a discussion of the results.

3.3.2.7.1 Generation Segment Analysis Numerical Results

The generation segment analysis was performed by linking each generating unit, or shares of generating units, to particular segments. The ownership and relationship of entities to segments was provided by ERCOT based on registration database information. Impacts for each generating unit were then aggregated to the segment level.

Table 3-21 through Table 3-24 show the results of the generation segment analysis for the Munis, COOPs, IOU Affiliates, and IPPs.

Table 3-21 Impact on Munis' Generation (Nodal – Base)

Municipality					
Year	Generation (GWh)	Generation Cost ($M)	Generation Revenue ($M)	Total Margin ($M)	Total Margin ($/MWh)
2005	424	23	62	39	1.19
2006	299	20	71	51	1.46
2007	175	13	68	55	1.58
2008	(113)	(0)	40	41	1.15
2009	(1,414)	(68)	(41)	27	0.74
2010	(3,338)	(144)	(180)	(36)	(1.00)
2011	(4,608)	(177)	(205)	(29)	(0.79)
2012	(2,876)	(121)	(161)	(40)	(1.11)
2013	(3,691)	(163)	(195)	(33)	(0.90)
2014	(2,204)	(105)	(42)	64	1.91
Total	—	(722)	(583)	139	—
Average	(1,735)	(72)	(58)	14	0.42
NPV	—	(486)	(357)	129	—

Table 3-22 Impact on COOPs' Generation (Nodal – Base)

Cooperatives					
Year	**Generation (GWh)**	**Generation Cost ($M)**	**Generation Revenue ($M)**	**Total Margin ($M)**	**Total Margin ($/MWh)**
2005	**25**	**2**	**(27)**	**(29)**	**(1.74)**
2006	**279**	**11**	**10**	**(0)**	**(0.03)**
2007	**237**	**9**	**16**	**7**	**0.41**
2008	**122**	**2**	**4**	**2**	**0.09**
2009	**(614)**	**(43)**	**(47)**	**(4)**	**(0.20)**
2010	**(502)**	**(33)**	**(55)**	**(22)**	**(1.28)**
2011	**(809)**	**(41)**	**(68)**	**(27)**	**(1.56)**
2012	**(477)**	**(33)**	**(65)**	**(31)**	**(1.89)**
2013	**(380)**	**(32)**	**(73)**	**(41)**	**(2.52)**
2014	**(67)**	**(24)**	**(21)**	**3**	**0.19**
Total	**—**	**(183)**	**(326)**	**(143)**	**—**
Average	**(219)**	**(18)**	**(33)**	**(14)**	**(0.85)**
NPV	**—**	**(124)**	**(230)**	**(105)**	**—**

Table 3-23 Impact on IOU Affiliates' Generation (Nodal – Base)

IOU Affiliates					
Year	**Generation (GWh)**	**Generation Cost ($M)**	**Generation Revenue ($M)**	**Total Margin ($M)**	**Total Margin ($/MWh)**
2005	**(1,196)**	**(62)**	**(356)**	**(294)**	**(2.38)**
2006	**(2,587)**	**(125)**	**(438)**	**(313)**	**(2.50)**
2007	**(2,858)**	**(132)**	**(480)**	**(348)**	**(2.74)**
2008	**(3,017)**	**(138)**	**(541)**	**(403)**	**(3.14)**
2009	**(1,715)**	**(71)**	**(224)**	**(153)**	**(1.18)**
2010	**676**	**36**	**(98)**	**(134)**	**(1.06)**
2011	**7**	**10**	**(81)**	**(91)**	**(0.72)**
2012	**224**	**24**	**(116)**	**(140)**	**(1.11)**
2013	**105**	**24**	**(108)**	**(133)**	**(1.05)**
2014	**(636)**	**(17)**	**(45)**	**(28)**	**(0.22)**
Total	**—**	**(451)**	**(2,488)**	**(2,037)**	**—**
Average	**(1,100)**	**(45)**	**(249)**	**(204)**	**(1.61)**
NPV	**—**	**(400)**	**(2,079)**	**(1,679)**	**—**

Table 3-24 Impact on IPPs' Generation (Nodal – Base)

IPPs					
Year	**Generation (GWh)**	**Generation Cost ($M)**	**Generation Revenue ($M)**	**Total Margin ($M)**	**Total Margin ($/MWh)**
2005	**539**	**8**	**(419)**	**(427)**	**(3.41)**
2006	**(1,021)**	**(55)**	**(441)**	**(387)**	**(3.01)**
2007	**(1,322)**	**(62)**	**(460)**	**(398)**	**(2.94)**
2008	**(381)**	**(32)**	**(436)**	**(404)**	**(2.86)**
2009	**3,588**	**105**	**(78)**	**(183)**	**(1.28)**
2010	**5,310**	**147**	**22**	**(125)**	**(0.91)**
2011	**585**	**8**	**(100)**	**(108)**	**(0.80)**
2012	**(932)**	**(48)**	**(151)**	**(104)**	**(0.79)**
2013	**3,336**	**93**	**(11)**	**(104)**	**(0.82)**
2014	**7,637**	**227**	**144**	**(803)**	**(6.88)**
Total	**—**	**393**	**(1,931)**	**(3,044)**	**—**
Average	**1,734**	**39**	**(193)**	**(304)**	**(2.37)**
NPV	**—**	**244**	**(1,692)**	**(2,378)**	**—**

3.3.2.7.2 Load Segment Analysis Numerical Results

Table 3-25 and Table 3-26contain the numerical results of the impact of the cost to serve loads, including the impact of the congestion rent refund, for each of the four load segments. The summary impacts are shown as the difference between the Nodal and Base Cases. Table 3-25 shows total dollar impacts and Table 3-26 shows impacts on a per-MWh basis.

Table 3-25 Segment Analysis Impact on the Cost of Served Loads after Congestion Rent Refund

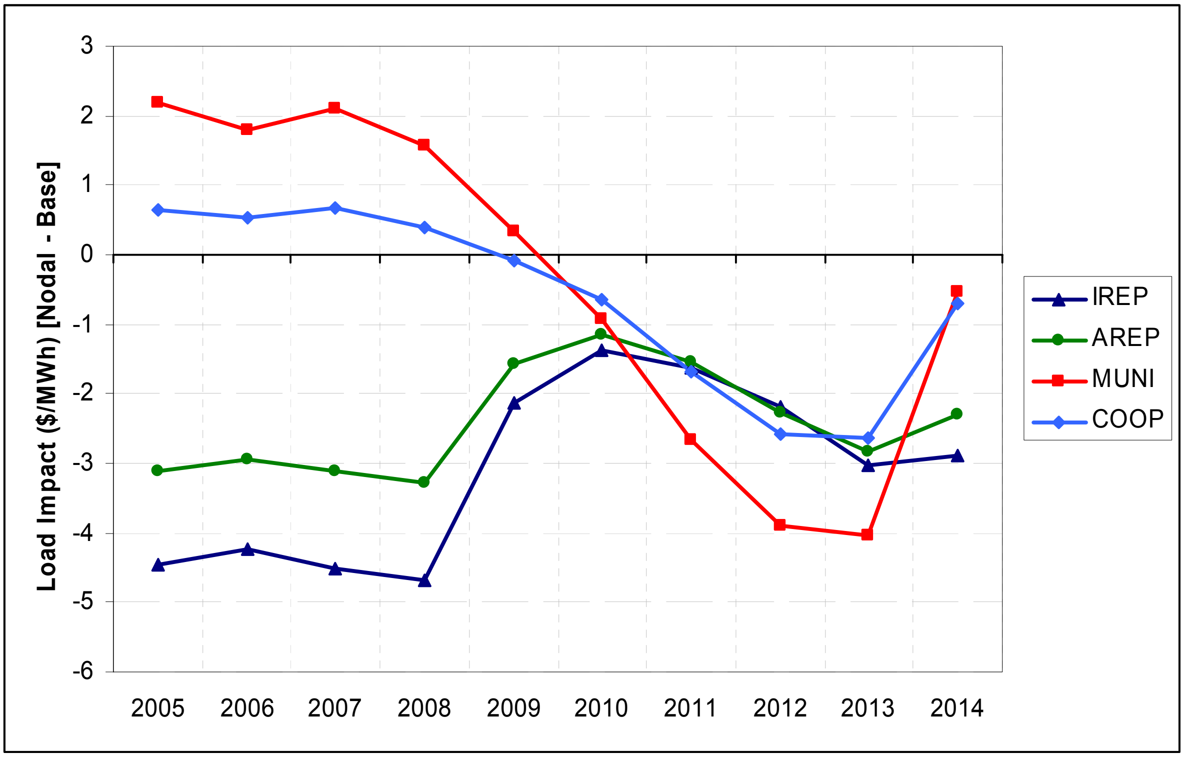
Difference ($M)					
Year	**IREP**	**AREP**	**MUNI**	**COOPS**	**Total**
2005	**(410)**	**(541)**	**97**	**20**	**(834)**
2006	**(399)**	**(521)**	**81**	**17**	**(822)**
2007	**(436)**	**(568)**	**98**	**22**	**(884)**
2008	**(463)**	**(611)**	**75**	**13**	**(987)**
2009	**(216)**	**(300)**	**16**	**(3)**	**(503)**
2010	**(143)**	**(225)**	**(46)**	**(23)**	**(437)**
2011	**(171)**	**(311)**	**(135)**	**(59)**	**(676)**
2012	**(236)**	**(463)**	**(203)**	**(93)**	**(995)**
2013	**(335)**	**(589)**	**(214)**	**(97)**	**(1,235)**
2014	**(326)**	**(487)**	**(29)**	**(26)**	**(868)**
Total	**(3,137)**	**(4,616)**	**(259)**	**(229)**	**(8,241)**
Average	**(314)**	**(462)**	**(26)**	**(23)**	**(824)**
NPV	**(2,485)**	**(3,597)**	**(98)**	**(138)**	**(6,318)**

Table 3-26 Segment Analysis: Impact on the Cost of Served Loads after Congestion Rent Refund ($/MWh)

Difference ($/MWh)				
Year	**IREP**	**AREP**	**MUNI**	**COOPS**
2005	**(4.46)**	**(3.12)**	**2.20**	**0.65**
2006	**(4.25)**	**(2.93)**	**1.79**	**0.54**
2007	**(4.52)**	**(3.12)**	**2.11**	**0.67**
2008	**(4.69)**	**(3.28)**	**1.58**	**0.40**
2009	**(2.14)**	**(1.57)**	**0.33**	**(0.07)**
2010	**(1.39)**	**(1.15)**	**(0.91)**	**(0.66)**
2011	**(1.62)**	**(1.56)**	**(2.66)**	**(1.67)**
2012	**(2.19)**	**(2.27)**	**(3.90)**	**(2.58)**
2013	**(3.04)**	**(2.83)**	**(4.03)**	**(2.64)**
2014	**(2.90)**	**(2.29)**	**(0.54)**	**(0.69)**
Average	**(3)**	**(2.42)**	**(0.39)**	**(0.60)**

Figure 3-12 graphically displays these load impacts by segment over the study horizon.

Figure 3-12 Summary of Load Impact by Segment ($/MWh)



3.3.2.7.3 Segment Analysis Discussion

For the IOUs, IPPs, AREPs, and IREPs, the load is spread fairly evenly across ERCOT. IOU Affiliates' and IPPs' generation results follow the average market trend. IREP and AREP load also follows the average market trend. IREP and AREP load on average benefits by an average of $2.4/MWh and $3/MWh respectively, more or less an average of the impacts across the zones. IPP generators see the greatest net revenue reduction with nodal ($2.4/MWh) but it is not disproportionately larger than the IOU Affiliate generation net margin reduction ($1.6/MWh).

The Muni and COOP impact is primarily driven by geography. Munis and COOPs serve loads mostly in the South and West Zones. (Some 89% of the load served by Munis is in South, and 75% of the load served by COOPs is in the South and West). South and West is where the cost to serve load increases in the near-term under the Nodal Case**.** Muni and COOP presence is minimal in the North zone and zero in the Houston zone.

Munis' generation margin is higher in the near-term with the Nodal Case. This follows the regional trend in the South zone, where most of their generation and loads are concentrated. The COOPs' generation margin is lower in near-term (2005 and 2006) with nodal. However, that trend reverses in 2007–2008, and is lower again with nodal in 2009 and beyond. This is due to the interplay of geography and the new entry trends.

While the results shown are the average annual results for the aggregate class, it should be noted that particular members of each segment may be impacted differently than these aggregated results suggest.[41]

3.3.2.8 ENERGY PRICE ANALYSIS

This section provides summary pricing information for each case over the study horizon. Prices are presented for both the Base and Change Cases. Figure 3-13 presents the on-peak monthly prices by zone for the Base Case. Note that these prices only pertain to the zonal MCPEs and do not include the cost of OOME (which can be significant, as discussed above).

Figure 3-13 Base Case On-Peak Monthly Prices (Real 2003 $/MWh)

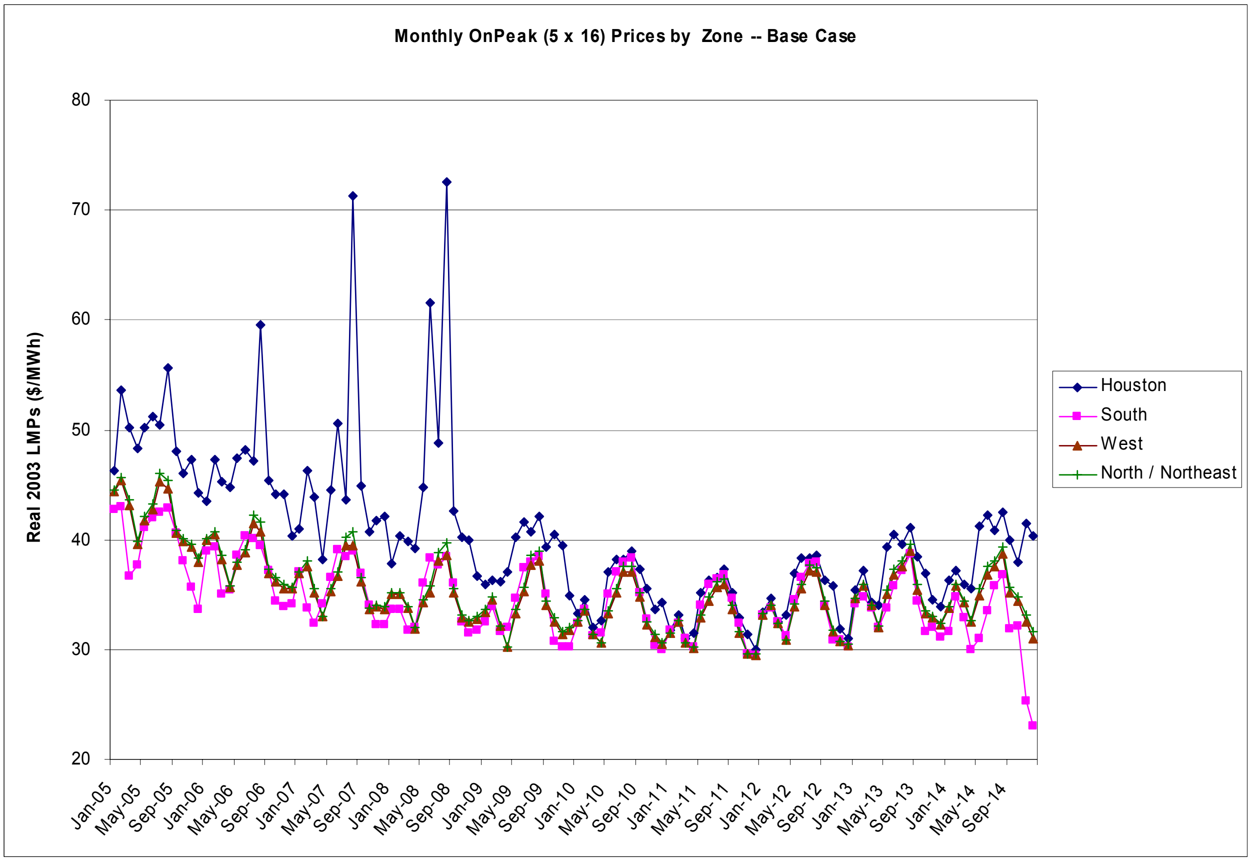


Figure 3-14 shows the Change Case load-weighted average on-peak nodal prices for each of the load zones, and Figure 3-17 shows similar Change Case results for other Metropolitan Service Areas (MSAs) of interest. Note, however, that loads in each of the MSAs will not under the current proposal be settled at the price shown in Figure 3-17. Rather, given the load aggregation policy, such loads will be settled at the zonal price of the zone to which it belongs, those prices shown in Figure 3-14.

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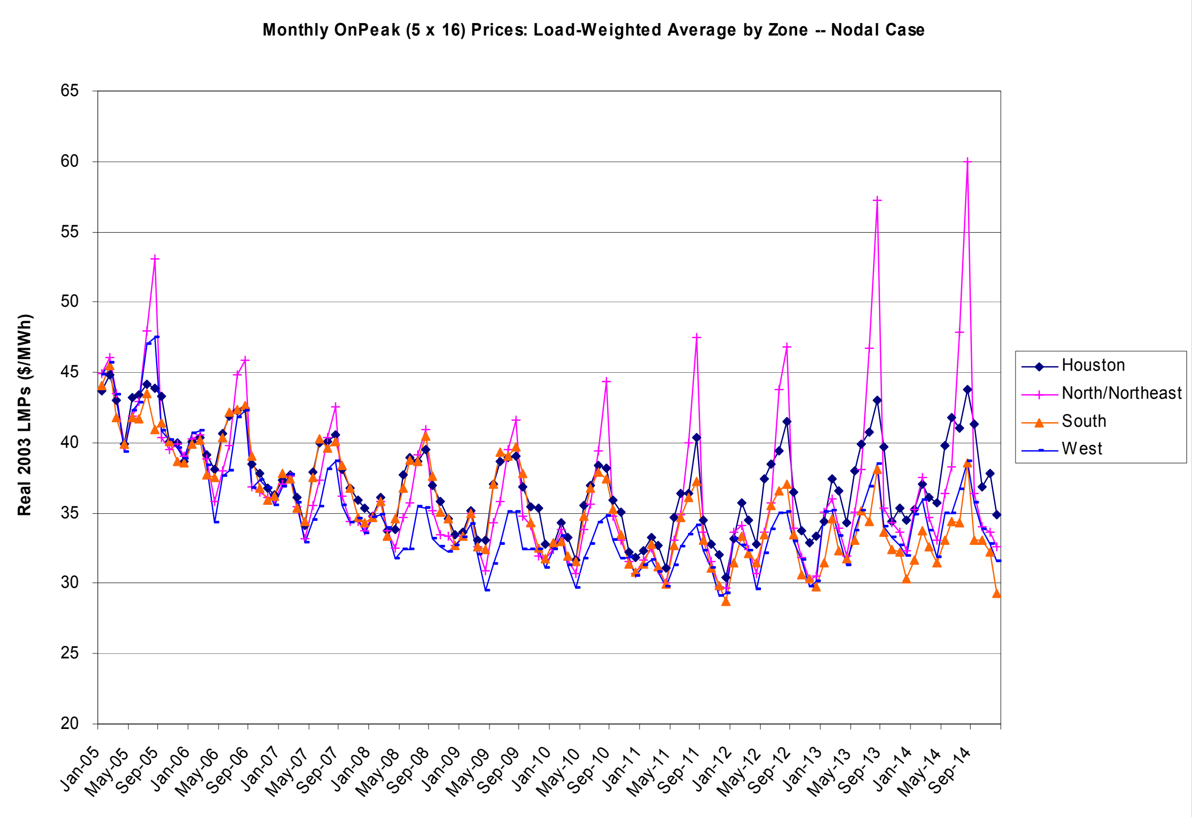
[41] TCA has not confirmed this one way or another, given that the method only examined the segment in total. However, by the nature the aggregation, the results for any members who are impacted differently than the entire segment trend will be masked by these aggregate results.

Figure 3-14 Change Case Load weighted LMPs by Zone (Real 2003 $/MWh)



Again, note that while nodal prices shown in these figures may be higher than the Base Case zonal prices, that does not mean that there are net adverse impacts to loads under the Nodal Case, nor does it mean that the pricing results are inconsistent with the earlier results conveying general savings to loads in each zone over the study period. Readers are reminded of two points made previously in the EIA discussions that distinguish energy pricing impacts from net payment impacts.

- First, in addition to the Base Case MCPEs (simulated values shown in Figure 3-13), loads in the zonal market also bear the costs of OOME payments to manage local congestion, whereas the costs of all congestion management are included in the Change Case nodal prices depicted in Figure 3-14.
- Second, the net results to load include the impact of the refund of congestion rents, and the refund of congestion rents is greater in the Nodal Case than in the Base Case. This is because OOME payments to manage local congestion do not create any congestion rent, whereas the management of local constraints in the Nodal Case does.

As an example, consider the North Zone, which is shown in Figure 3-14 with prices in the out years of the study that are elevated relative to the Base Case MCPEs shown in Figure 3-13. (Readers are also referred to Table 3-18 and Table 3-20. Table 3-18 shows the impacts of the Nodal Case to the North zone on a per MWh basis as being based on energy payments alone, Energy and OOME in the Base Case and Energy in the Nodal Case). Based on the energy payments alone, the results suggest that, on average over the study horizon, loads in the North zone would pay $0.14/MWh more under the Nodal Case. However, with the incorporation of the resulting congestion rent under each case and the return of this congestion rent to the load serving entities, loads in the North are expected to have net reductions on average of $1.24/MWh over the study horizon, as shown in Table 3-20.

One other observation from these pricing graphs is that a comparison of Houston prices from the Base Case (Figure 3-13) and the Nodal Case (Figure 3-14) provides another source of explanation for the significant results seen in Section 3.3.2.6, Regional Impacts, with respect to the generator and load impacts in Houston. (For example, see the Houston Results in Table 3-15 and Table 3-17.) The simulation shows that congestion management—especially with respect to the Houston zone—improves significantly with the nodal model. This allows additional flows into Houston, and reduces the prices in the Houston zone. In turn this creates net margin decreases for Houston generators and load benefits for Houston loads.

For this North zone example, Figure 3-15 and Figure 3-16 show the breakdown of the total payment (dark blue bar) and its constituent elements. The figures demonstrate that while the energy components are less in the Zonal Case than the Nodal Case, the total payments, without OOME and after the congestion rent refund, as indicated by the dark blue bars, are lower under the Nodal Case.

Figure 3-15 North Zone Cost Components for the Zonal Case including Congestion Rent (CR)

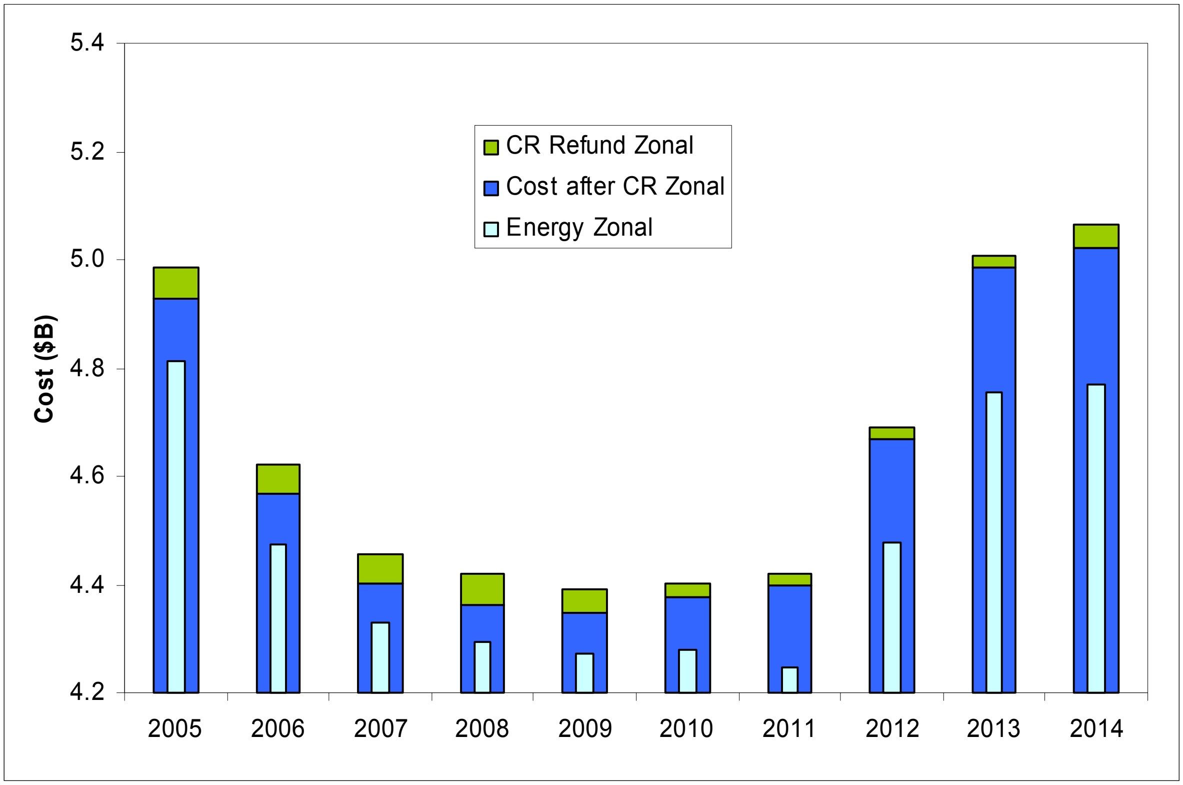


Figure 3-16 North Zone Cost Components for the Nodal Case including Congestion Rent (CR)

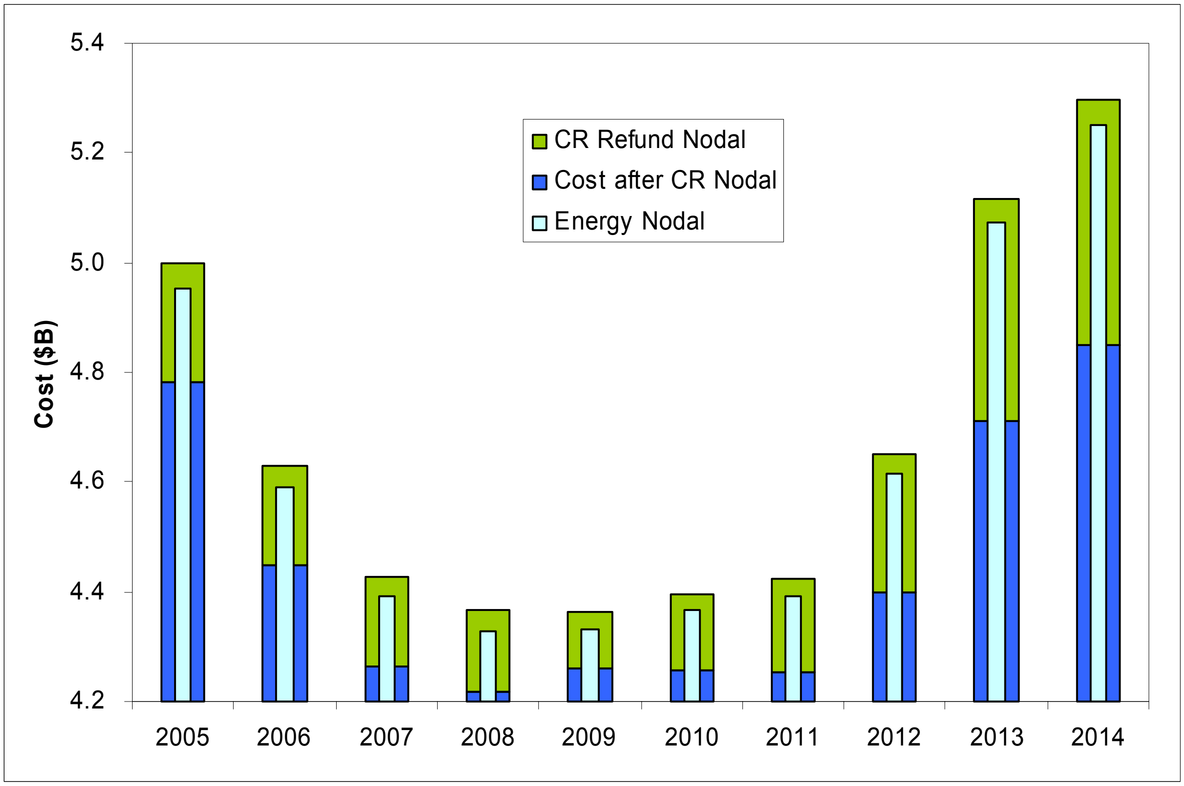
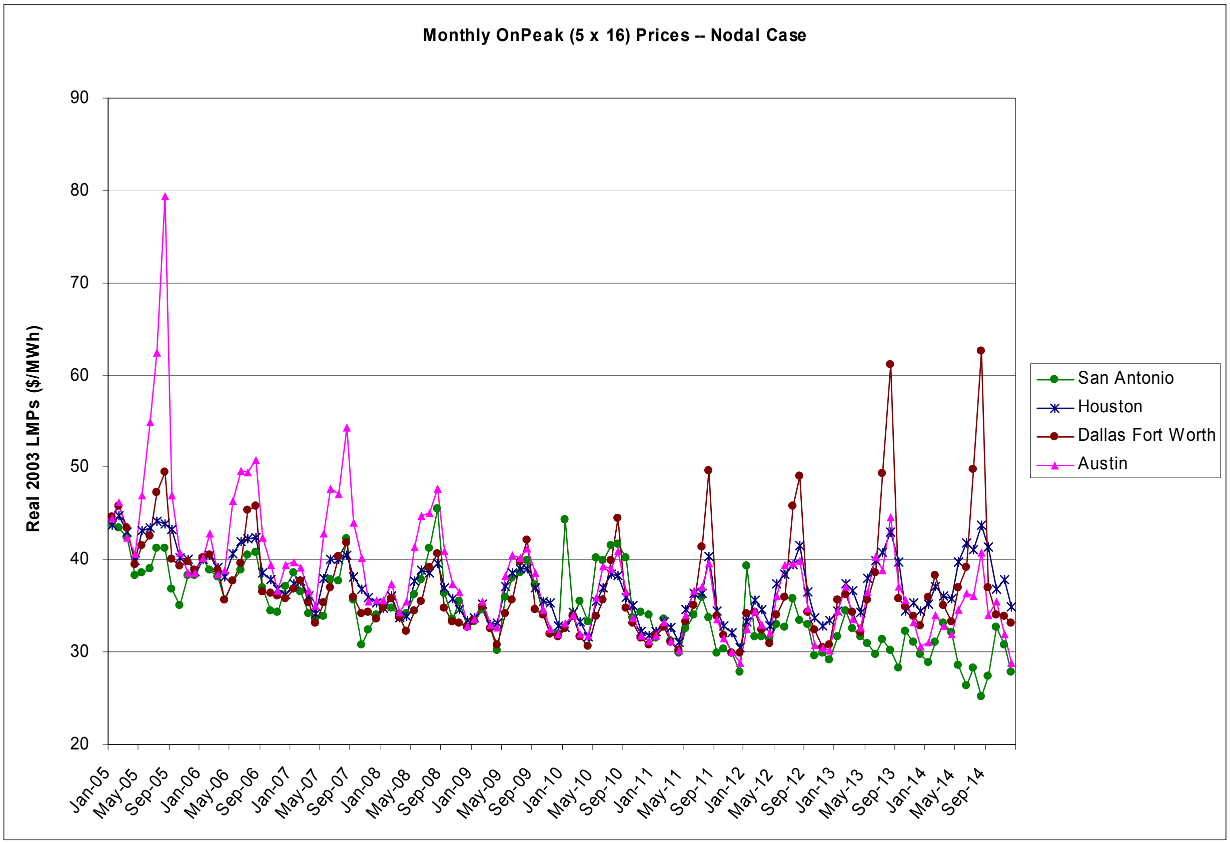


Figure 3-17 shows the load-weighted average prices for the MSAs.

Figure 3-17 Change Case Load weighted LMPs by MSA



The price spikes observed in the Austin MSA are likely the outcome of certain modeling assumptions, rather than a prediction of the likely future price trend in that area under the nodal market design. A detailed analysis of the transmission constraints that give rise to these particular price spikes indicates that these constraints should have been excluded from the analysis, had that information been available to TCA in time. Without re-running the model, TCA estimates that in absence of those transmission constraints, the Austin MSA price will likely follow prices in the South zone.[42]

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[42] The problematic contingency constraints were discovered by the ERCOT staff after all input and modeling assumptions had been finalized and simulation results had been produced. Although Austin Energy expressed concerns regarding the validity of their results, TCA believes that the underlying study remains valid for several reasons. Prices for the Austin MSA are reported for information purposes only and have never been used directly in the impact analysis on any zone or generator group. All load impact analysis has been conducted using average prices for the entire zone—all results that apply to Austin Energy obtained in this study were obtained with the use of the South Zone load-weighted average LMPs. Problematic constraints causing apparent spikes in the Austin MSA are the kind of overload constraints generally addressed by TCA in that study. TCA conducted several iterative simulation analyses to minimize the impact of overload constraints to the level believed to be acceptable. TCA does recognize that the Austin price results are not ideal for Austin's assessments of its potential NOIE Load Zone.

3.3.2.9 Economic Additions: New Entry Results

This section presents the outcome of the siting decisions incorporated into the modeling. Recall from Section 3.2.6 that the siting assumption discussions included the following attributes.

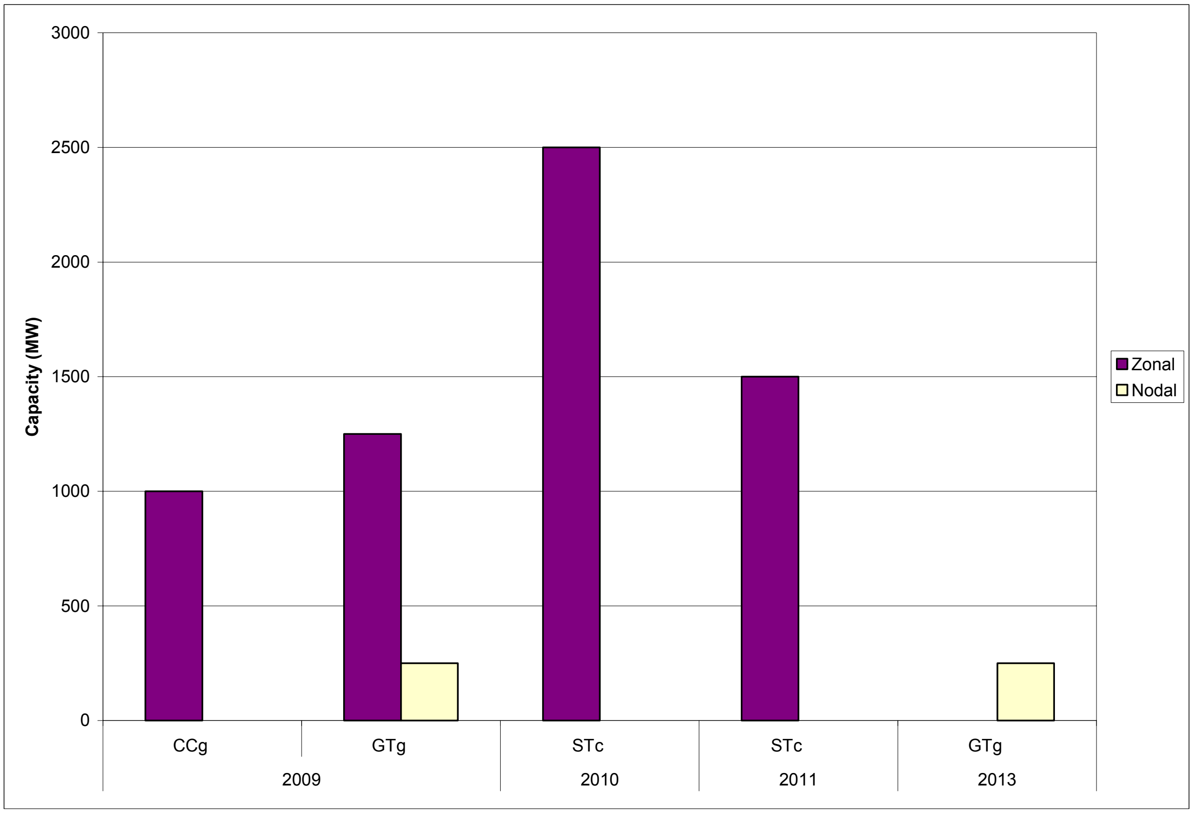
- Generation additions were driven by reliability requirements (12.5% reserve margin)
- The type and location of new generating units was based on economic signals created by the market design

Also, several types of resources were considered, including combined cycle (Gas), combustion turbine (Gas), and steam turbine (Coal). There were several limitations in the new entry modeling, including the following:

- No coal was added before 2010 (lead time)
- No coal was added in the metropolitan non-attainment areas such as Houston-Galveston or Dallas–Fort Worth
- All new entrants in the MSAs are 25% more expensive

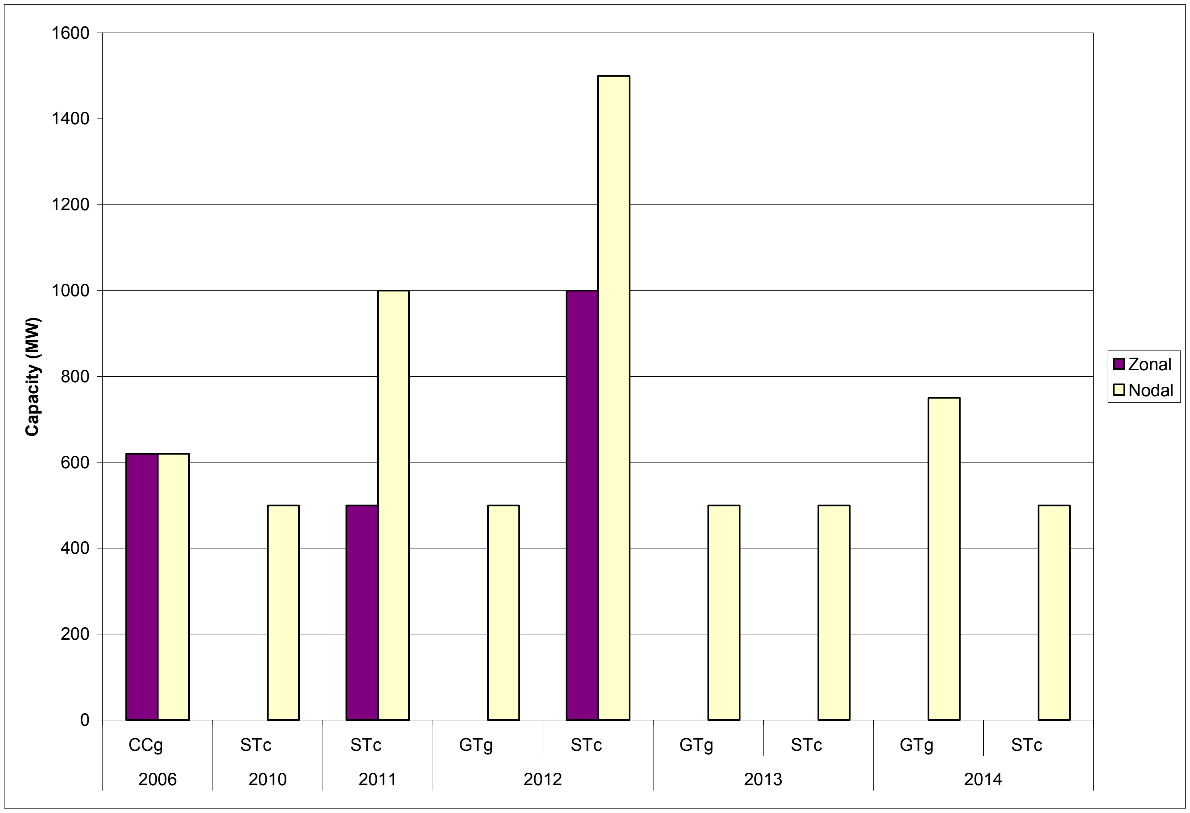
The new entry methodology was conducted over the course of the study years once the reserve margins were low enough and/or prices were high enough to support new entry. However, given that the load flow model used for the years 2009–2014 did not include any new transmission upgrades, the new entry approach had to be modified beginning in the year 2012 in order to site generation in the simulations that did not cause significant transmission issues. Thus, beginning in 2012, units could not always be sited at the most advantageous locations.

Figure 3-18 Houston Zone New Entry



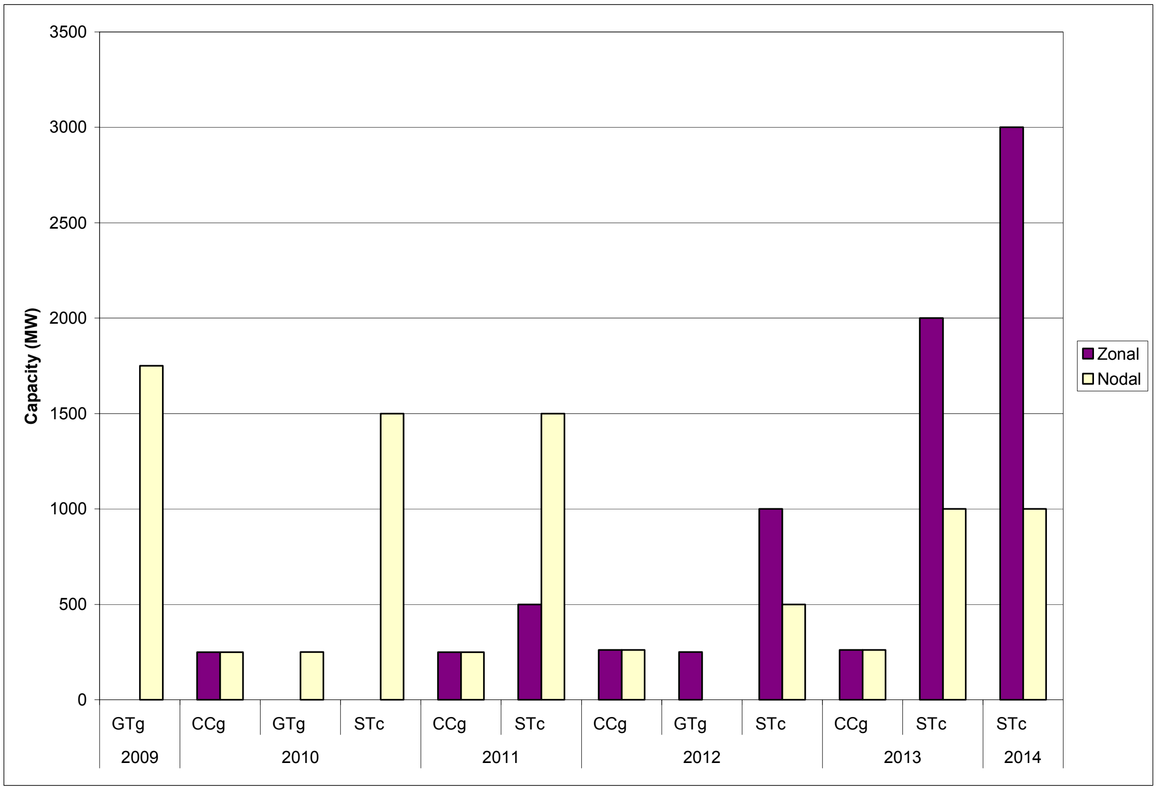
Under the Base Case scenario, a massive amount of new capacity is added in the Houston zone. This is consistent with price signals created by the zonal market design: zonal prices in Houston during 2009–2011 created strong signals for building new generation capacity in that zone. In 2009, 1000 MW of gas fired combined cycle generation and 1250 MW of simple cycle peaking capacity were added in the Houston zone. No coal-fired generation addition was allowed for 2009. 2500 MW of coal fired generation is added in the Houston zone in 2010 and 1500 MW in 2011. In contrast, under the Change Case scenario, LMPs in Houston are relatively low due to the ability to import power into Houston from the South zone. As a result, only two simple cycle peakers are added in that zone under the Change Case scenario, one in 2009, another in 2013.

Figure 3-19 North Zone New Entry



In 2006, a new Boonsville combined cycle unit is shown on Figure 3-18 for both Base and Change Cases. Persistent congestion inside the North Zone creates strong economic signals for adding a significant amount of new generating capacity in the North Zone in each year from 2010 to 2014. In each year except 2010, added capacity is a mix of coal-fired baseload generation and simple cycle gas-fired peaking units. Under the Base Case scenario, only in 2012, 1000 MW of coal-fired generation is added, attracted by the combination of zonal prices and an opportunity to earn OOME payments.

Figure 3-20 South Zone New Entry



The impact of the market redesign on the new entry strategy in the South is also significant. Under the Change Case scenario, a strong incentive exists to site new generation in the South (nodal design drives prices in the South above zonal prices under the Base Case). That, combined with the improved opportunity under the nodal design to export power to the Houston zone, attracts new generation in the South zone, primarily in 2009–2011 and to a lesser extent during 2012–2014. In contrast, no new generation is attracted in the South zone under the Base Case until 2011. Substantial additions of new coal fired generation occur in the South under the Base Case scenario in 2013 and 2014. Figure 3-22 shows an addition of combined cycle generation in each year 2010 through 2014. This capacity represents the return to service of the Hays units 1 through 4 from mothballed status.

In the West Zone, only one facility was added under the Change Case, a 500-MW coal facility in 2014. No other resources were added in the Base or Change Cases.

TCA analyzed the retirement of existing generating facilities in 2005–2008 under each scenario. A complete assessment of generation retirement requires an understanding of the market for capacity and developed resources adequacy standards. While no capacity market presently exists in ERCOT, in order to assess retirement, TCA had to estimate a capacity price in the market in each year as if some form of the installed capacity market were complementing the existing or proposed market design. Using that theoretical construct, TCA estimated the profitability of each generating unit in each year under each scenario. The following criterion was used: a unit was to be retired if it was more than $5/kW-year short of being profitable for two years in a row. Based on that criterion, however, no units were retired under either scenario.

As discussed in the Appendix 3-1 summarizing TCA input assumptions, a number of mothballed generating units have been considered as alternatives to new construction. Four Hays generating units were recommissioned over the period 2010–2014 under both scenarios.

3.3.2.10 GENERATION MIX COMPARISON

This section summarizes the differences in production by unit type for the Base Case and the Change Case. In general, there are no major differences in generation production by type (generation mix) between the two cases in the near term. However, subtle differences in siting drive rather significant price implications in the later years of the study.

For example, under the Change Case in 2005 total generation in Houston decreases by approximately 1100 MW:

- 560 MW decrease in combined cycle output,
- 390 MW decrease in the combustion turbine output, and
- slightly less than 1000 MW decrease in steam-turbine (gas) output.

That Houston decrease is combined with approximately 1900 MW of increased generation in the South:

- 1100MW of which is consumed in Houston, and
- 800 MW of which is wheeled through Houston to the North zone.

In contrast to the Houston zone generation mix change compared to the Base Case, combined cycle output in the South zone increased by 1500 MW, combustion turbine output increased by 200 MW, and steam turbine (gas) output increased by 270 MW. In relative terms, these changes do not appear significant. The resulting changes in average generation costs are minimal: 2.5% increase in average generation costs in the South and 2.5% reduction in average generation cost in Houston. However, the impact on prices is quite significant: the annual average price in Houston decreases by 12%, whereas the annual average price in the South increases by 12%.

Differences in the mid- and long-term are driven by differences in new entry strategies simulated for each market design.

Figure 3-21 through Figure 3-23 show the changes in mix in a sampling of the study years: 2005, 2008 and 2011. Numerical results for production by unit type, capacity factors, and costs are shown in Appendix 3-4.

Figure 3-21 Generation Mix Analysis for 2005 (TWh)

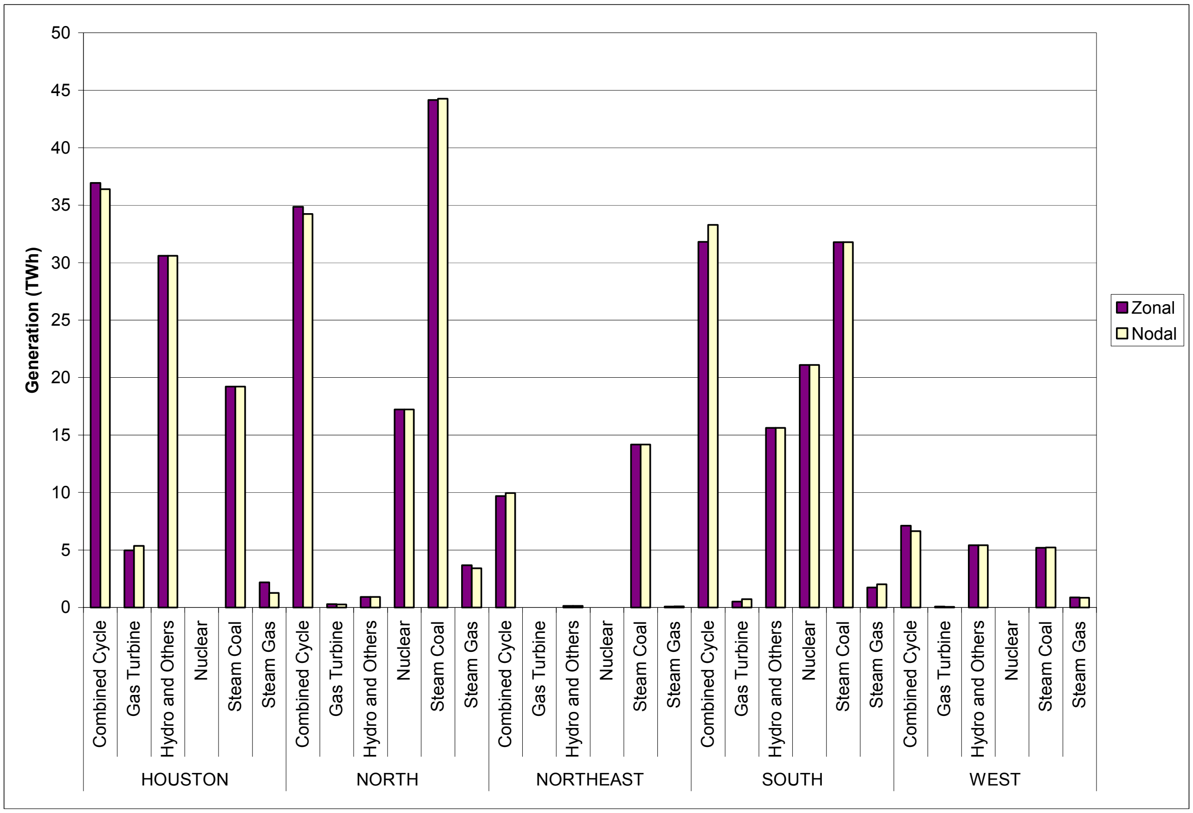


Figure 3-22 Generation Mix Analysis for 2008 (TWh)

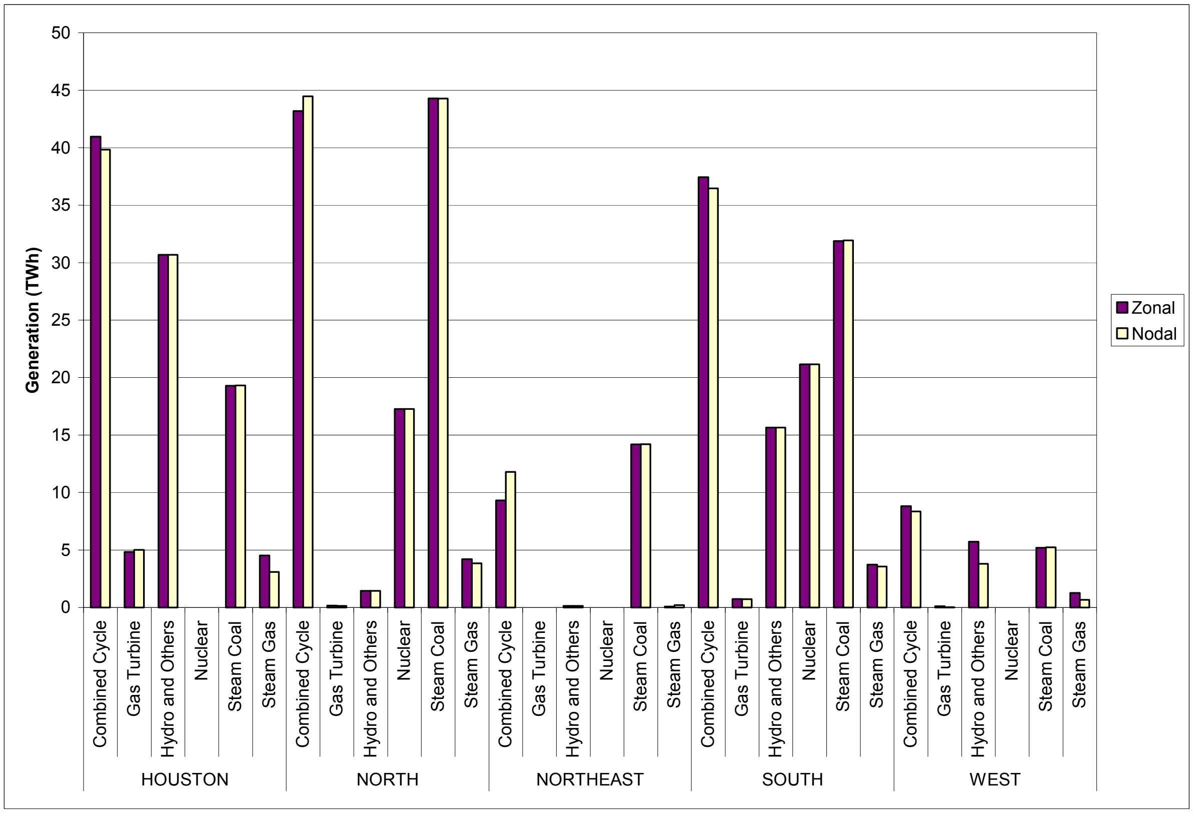
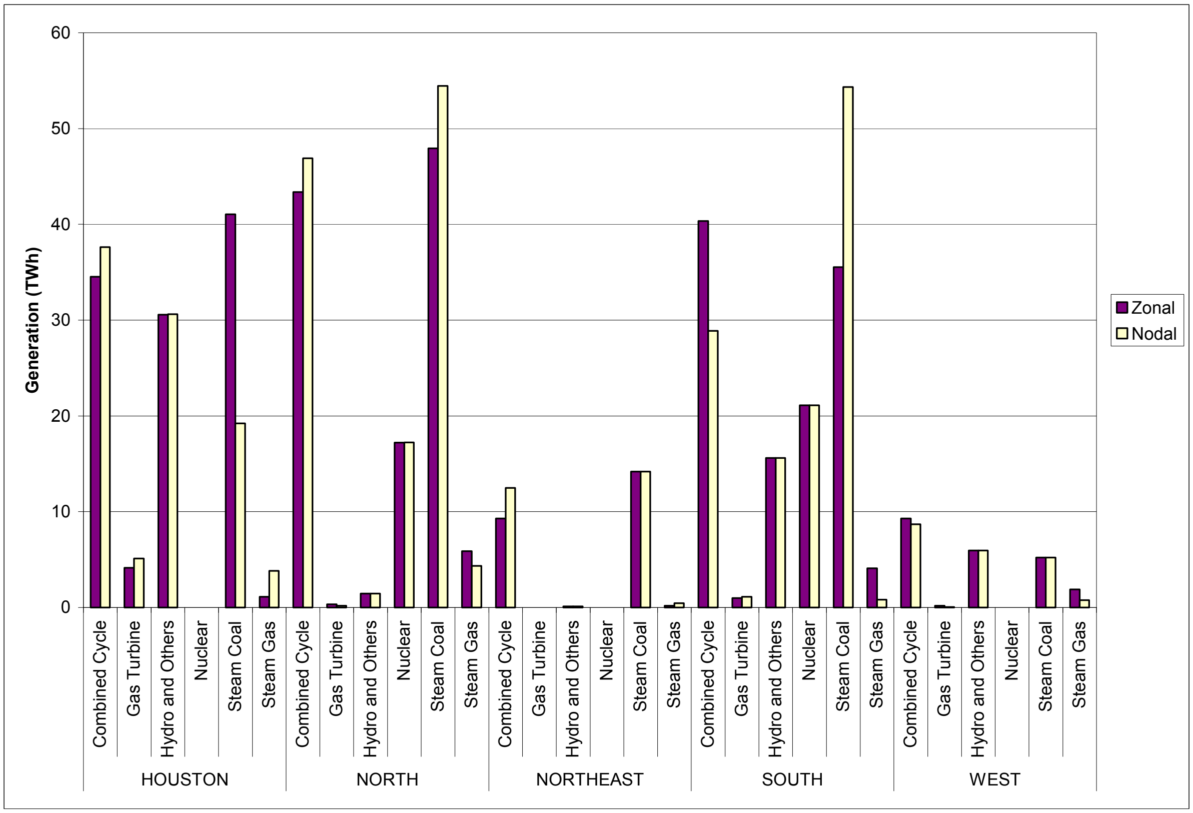


Figure 3-23 Generation Mix analysis for 2011 (TWh)



3.3.2.10.1 Emission Impacts

Table 3-27 shows the difference in emissions rates between the Nodal Case and the Base Case. Given the mix of resources under the Nodal Case, the NO_x emissions decrease while the SO_x emissions increase, compensating somewhat for the reduction in NO_x emissions. This dynamic is due to certain changes in the generation mix. On one hand, under the Nodal Case, some output of steam turbine gas-fired generators is replaced with the output of more efficient combined cycle plants. That results in the reduction of NO_x emissions. On the other hand, better congestion management introduced by the nodal market design slightly increases the capacity factor of coal-fired generators resulting in a slight increase in SO_x emissions.

Table 3-27 Emissions Impacted Tons (Nodal – Base)

Year	NO_x Emissions (Tons)	SO_x Emissions (Tons)
2005	413	493
2006	(914)	187
2007	(1,290)	80
2008	(1,847)	277
2009	(3,571)	575
2010	(4,567)	(73)
2011	(6,653)	165
2012	(5,211)	561
2013	(4,812)	550
2014	(4,249)	1,385
Total	(32,700)	4,200
Average	(3,270)	420

3.4 Energy Impact Assessment Conclusions

The 2005–2014 simulations show with the Nodal (Change) Case:

- A system-wide average production (generation) cost savings of $76 million per year. This simulation result can be interpreted to be the simulated average increase in system social welfare per year over the study horizon

- A shift in value from Generators to Loads: Loads pay on average $822 million per year less ($289 million less for energy and OOM-as applicable, adjusted by congestion rent refunds of $533 million). Loads in Houston see the largest cost savings, followed by loads in the north. Generators as a class receive on average $858 million less per year. Net of costs (which go down) their margin is on average $780 million per year less. Generators' margin impacts vary by zone. Houston, North and West margins decrease, and Northeast and South margins increase.

Segmentation yielded:

- Generation Margins—average change with Nodal Case[43] (note: not all generators mapped to one of these four segments)

Munis:	$ 14 million increase
COOPs:	$ 14 million decrease
IOU Affiliates:	$204 million decrease
IPPs:	$304 million decrease

- Loads—each segment sees net load payment (energy cost less congestion rent refunded) reduction over the study horizon, though the Munis and COOPs see net increases over the first 5 and 4 (respectively) study years, and their average savings is significantly lower. Annual average impacts were:

Table 3-28 Load Share and Benefits by Segment

Type	Load Share (%)	Average Annual Benefit ($M)	Load-Normalized Benefit Share (%)
IREP	27	314	38
AREP	51	462	56
MUNI	15	26	3
COOPS	8	23	3

Peak zonal prices in the North zone are shown to increase under the Nodal Case, yet loads, on average, in all zones are expected to see benefits given the reduction in OOME payments and the impacts after congestion rent refunds occur.

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[43] Note that the segment analysis did not yield a complete segmentation, so that these segment results will not sum to the total of the ERCOT-wide results.

4 Backcast Analysis

TCA performed an analysis comparing GE-MAPS simulated generation dispatch results for 2003 with actual historical generation dispatch results experienced in ERCOT in 2003. This analysis, referred to as the Backcast analysis, is presented in this section. The Backcast analysis is not a comparison of the existing Base Case with the Nodal Case. Rather it is a comparison of simulated generation with actual generation. A simulation of the ERCOT zonal model for 2003 was used to generate the simulated hourly dispatch that the GE-MAPS model shows as optimal.

The purpose of the Backcast was to provide the comparative results parties believed may be useful to examining the difference between the efficient/optimal dispatch and the actual dispatch. Note that the Backcast was neither intended nor designed to serve as a benchmarking activity. In other words, it was not conducted to validate the EIA results, nor is it appropriate to interpret its results in that fashion.

4.1 Description of Analysis

TCA performed a simulation using the same GE-MAPS simulation platform as used in the balance of the EIA. The year 2003 simulation included the use of actual fuel prices at hubs, converted to burner-tip prices using the same TCA fuel methodology applied to the 2005–2014 EIA simulations, and of actual generating plant outages and actual load energy and load shapes as provided by ERCOT staff. TCA also modeled the four-zone configuration applicable in 2003.

Actual hourly dispatch data for generating plants were obtained from ERCOT staff. The ERCOT data were mapped to the generating plants in the TCA simulations for comparison. TCA's generating plant cost-characteristics were deemed by the market participants to be a useful and consistent means of translating plant dispatch differences resulting from the Backcast into dollar implications.

The following summarizes the data sources:

- ERCOT Data:
    - Actual generation (15 min settlement data) from ERCOT
    - Generator outages from ERCOT
    - Generators mapped to the load flow
    - Load flow provided by ERCOT
    - Hourly loads served provided by ERCOT
    - Self-served loads identified on the load flow
    - Behind-the-fence generators identified in the load flow
    - Hourly schedules for hydro and wind generators provided by ERCOT
- TCA Data:
    - Generators database (capacities, emission rated, Variable Operating and Maintenance heat rates)
    - Generators mapped to the load flow
    - 2003 Monthly fuel prices per Platt's and other sources

- 2003 Monthly emission permit prices (Cantor Fitzgerald)

Reliability Must Run units are included in both the simulated and actual results. Given that RMR units are used for local congestion management, the Backcast zonal simulation would treat the RMR units in a manner consistent with ERCOT's treatment, allowing them to generate for local congestion when needed. As a result, there should be no additional generation in the actual case from the RMR units. Because the simulations are cost-based, the dispatch of the RMR units for congestion management is based on the units' marginal costs. Finally, given that TCA's cost structures were used to price the costs of production in both the simulated results and the actual dispatch, RMR units should not incorrectly influence the Backcast results.

Several possible study approaches were specifically excluded from the simulation, primarily for feasibility reasons:

- Actual transmission element outages were not modeled
- Actual generator bids were not modeled
- Generating bids other than marginal cost bids were not modeled[44]
- A full representation of the actual ERCOT ancillary service markets was not modeled[45]

The results were assessed by making comparisons on a unit-by-unit basis and aggregating results to meaningful levels. Given that TCA is comparing theoretical simulated results with actual market events, and given that actual transmission outages are not simulated, comparison of specific units or of specific intervals of time can be problematic. Aggregated results, conveying overall outcomes, can be regarded as much more meaningful.

4.2 Backcast Results

This section presents the results of the Backcast analysis. Table 4-1 shows the metrics based on the actual system dispatch and the metrics based on TCA's simulated dispatch.

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[44] In a market operating at a competitive equilibrium, producers will bid marginal cost.— That is, they will set output to the level at which marginal cost equals the market price: Stoft, Steven, *Power System Economics: Designing Markets for Electricity* (Wiley-IEEE, 2002), pp. 56–57. In GE MAPS the marginal cost is equal to the variable O&M plus the fuel cost of the next level of production, as adjusted for environmental adders.

[45] Note that in the EIA the lack of a full representation of the ancillary service markets is not especially significant given that the measurement of impacts includes that representation in both cases. With this Backcast, however, simulated dispatch is being compared with actual dispatch. To the extent market participants factor in the value of ancillary services into their actual commitment and dispatch decisions, one would expect the actual dispatch to vary from the simulated dispatch.

Table 4-1 Backcast Side-by-Side Analysis

	Using Actual Dispatch			Using Simulated Dispatch		
Zone	**Generation (TWh)**	**Generation Cost ($B)**	**Average Cost ($/MWh)**	**Generation (TWh)**	**Generation Cost ($B)**	**Average Cost ($/MWh)**
ERCOT	**277.4**	**8.1**	**29.1**	**273.2**	**6.9**	**25.4**
Houston	**55.2**	**2.1**	**38.0**	**60.3**	**1.9**	**31.6**
North	**121.6**	**3.2**	**26.2**	**118.1**	**2.9**	**24.2**
South	**82.8**	**2.2**	**26.4**	**76.1**	**1.7**	**22.0**
West	**17.8**	**0.6**	**34.4**	**18.7**	**0.5**	**27.2**

The Backcast differences (actual – simulated) from the Backcast comparisons are shown in Table 4-2. The table shows actual generation costs from the dispatch to be $2 billion greater than the simulated cost, between 9% and 23% more than the simulated amounts across the various zones.

Table 4-2 Backcast Side-by-Side Analysis—Delta (Actual – Simulated)

Delta (Actual – Simulated)					
Zone	**Generation (GWh)**	**Generation Cost ($M)**	**Average Cost ($/MWh)**	**Generation (% of Actual)**	**Generation Cost (% of Actual)**
ERCOT	**4,231**	**1,132**	**3.7**	**1.5%**	**14.0%**
Houston	**(5,129)**	**186**	**6.3**	**–9.3%**	**8.9%**
North	**3,522**	**335**	**2.1**	**2.9%**	**10.5%**
South	**6,680**	**506**	**4.3**	**8.1%**	**23.2%**
West	**(841)**	**106**	**7.2**	**–4.7%**	**17.2%**
Total	**8,463**	**2,264**	**—**	**—**	**—**

The following metrics offer details into the nature of the differences between the actual and simulated results. Figure 4-1 and Figure 4-2 indicate the differences in generation and generation cost by zone, and Figure 4-3 and Figure 4-4 indicate these results by unit type.

Figure 4-1 Generation by Zone: Actual vs. Simulated

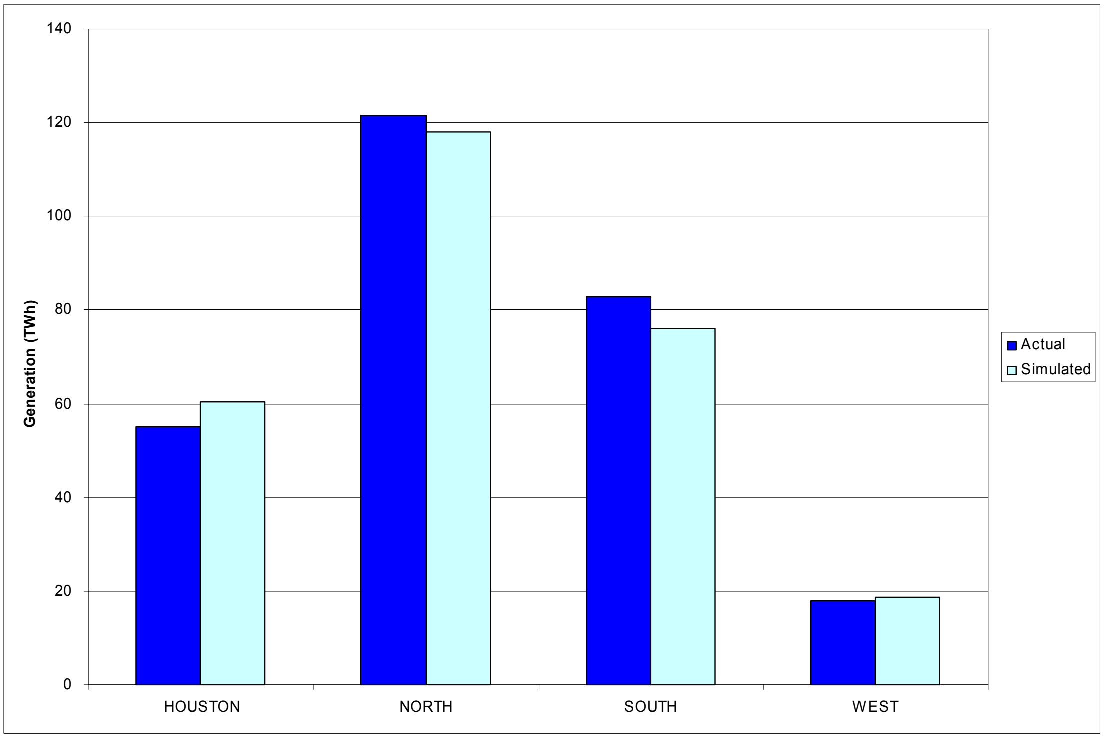


Figure 4-2 Generation Cost by Zone: Actual vs. Simulated

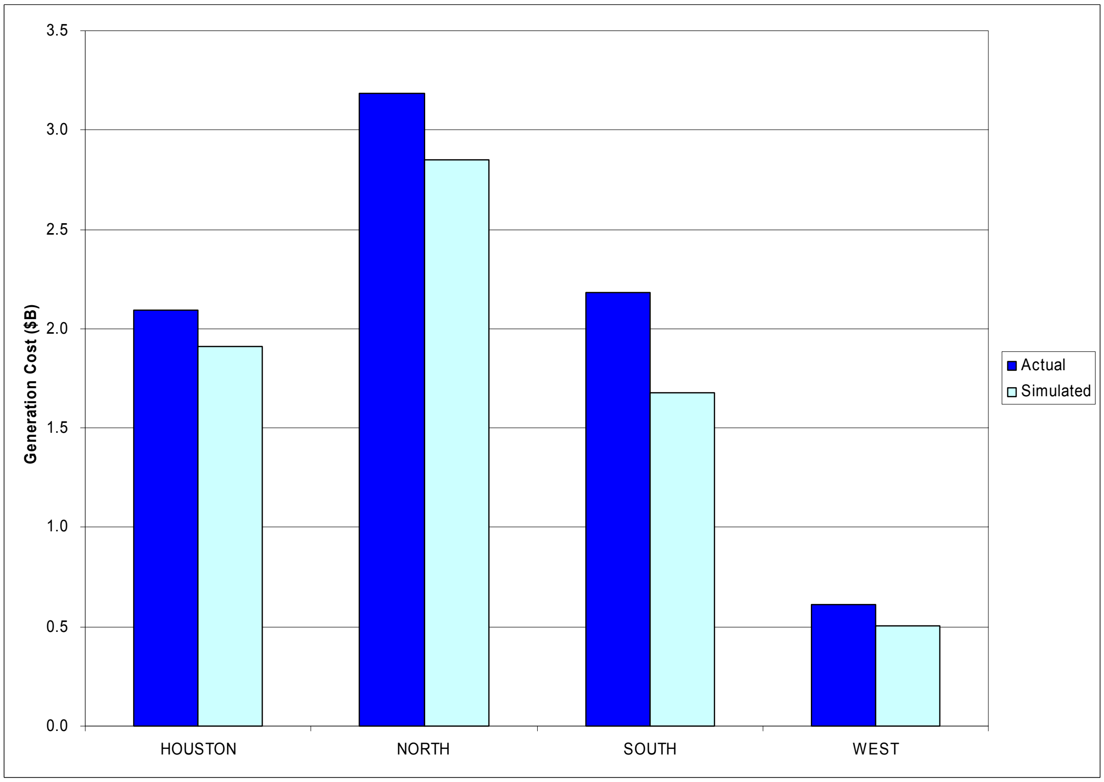


Figure 4-3 Generation Mix: Actual vs. Simulated

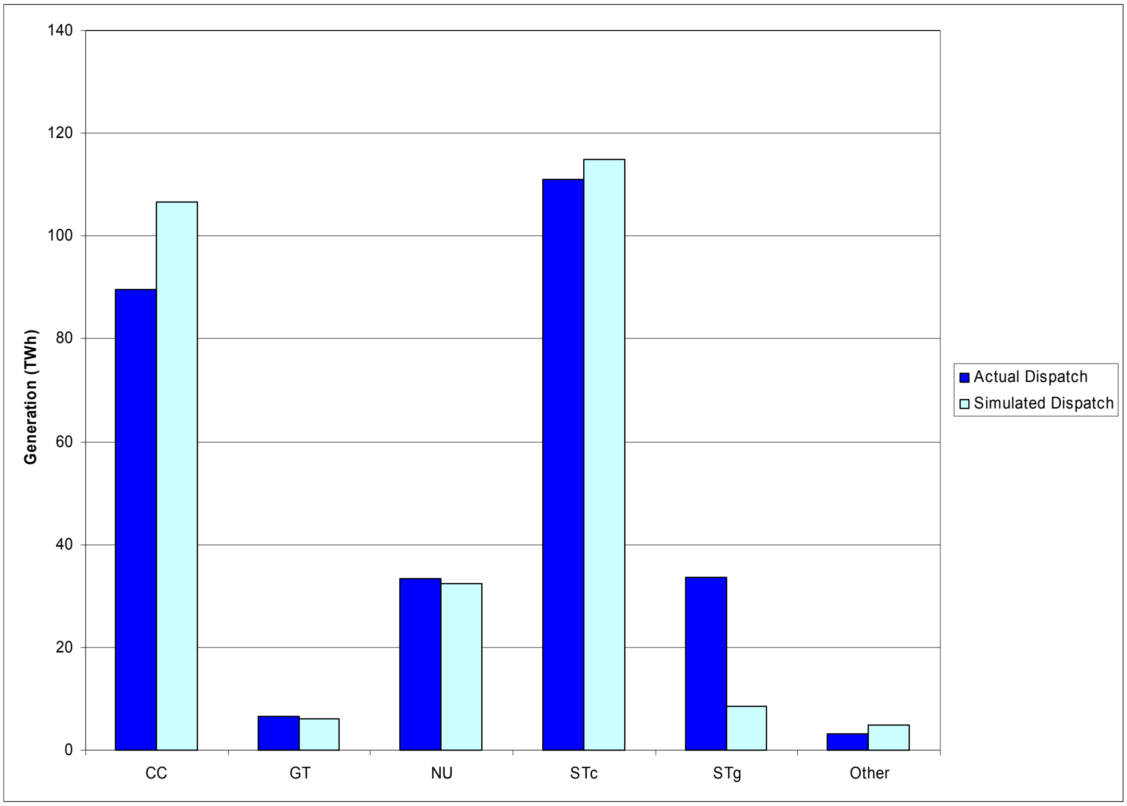


Figure 4-4 Generation Mix Cost: Actual vs. Simulated

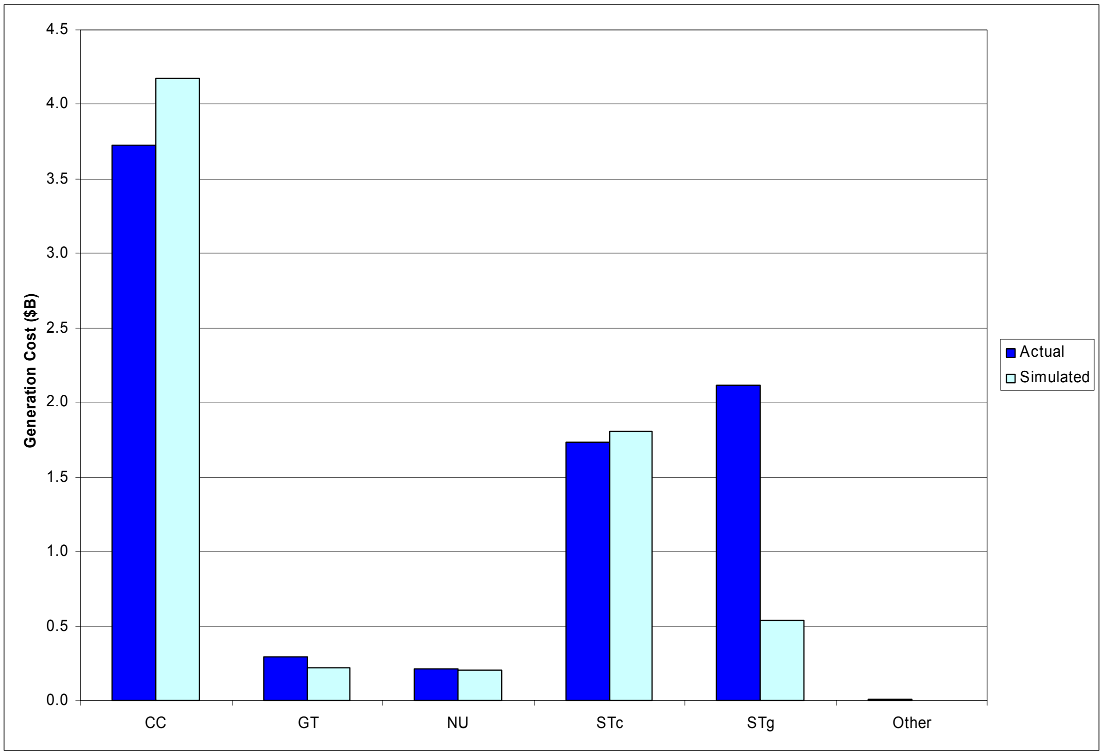


Figure 4-5 and Figure 4-6 indicate the actual vs. simulated differences by segment.

Figure 4-5 Generation by Owner Type: Actual vs. Simulated

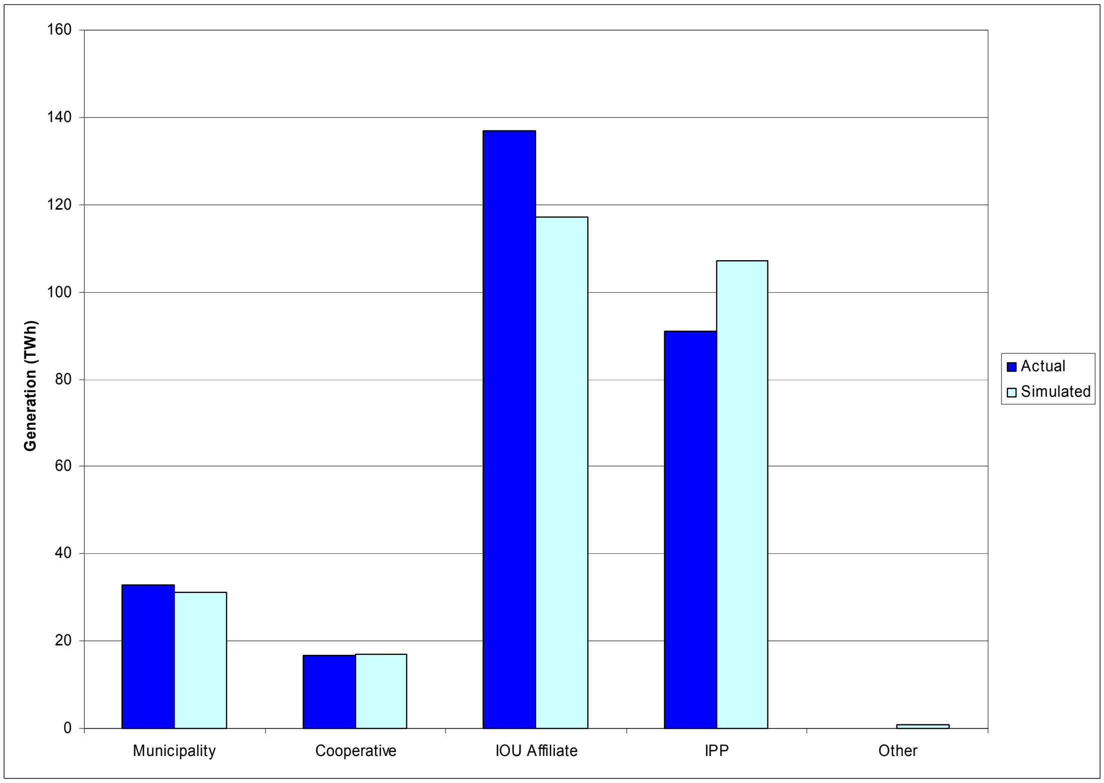
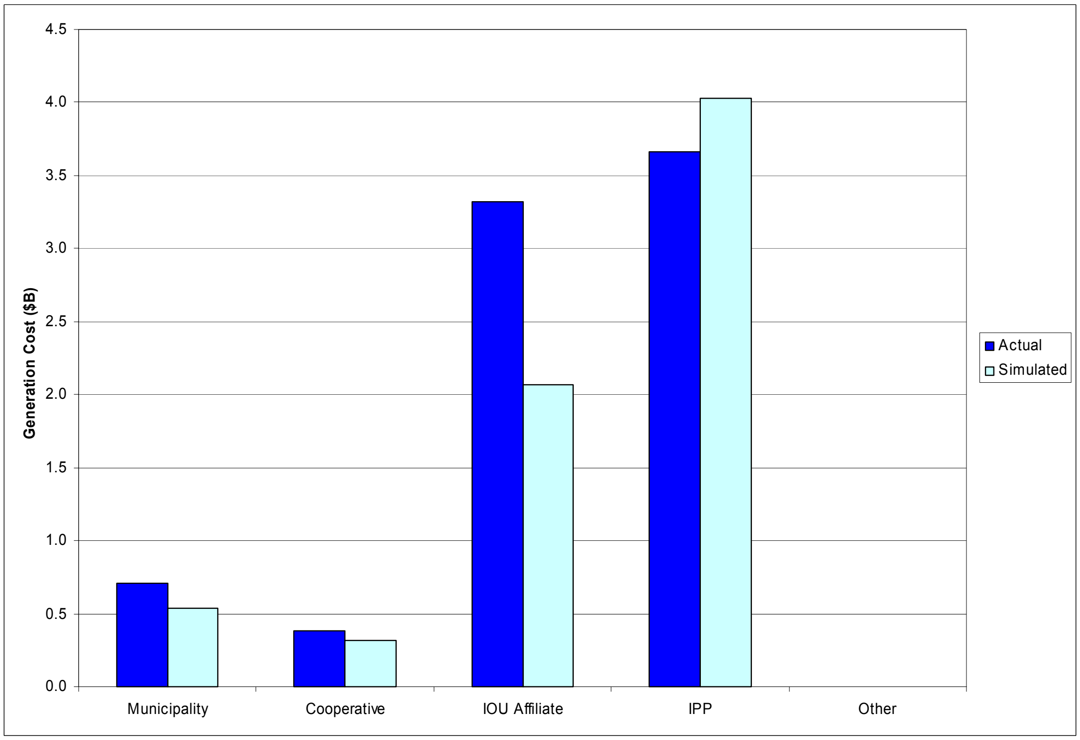


Figure 4-6 Generation Cost by Owner Type: Actual vs. Simulated



4.2.1 Backcast: Discussion of Results

The data show the actual ERCOT generation cost of over $1 billion per year (16%) greater than the simulated zonal model resulting costs. Approximately half of this difference occurs in the South zone, approximately one third occurs in the North zone, and the balance occurs in Houston and the West zone.

The results by unit type indicate that steam-turbine gas plant type generation actually experienced in the 2003 ERCOT market was greater than simulated steam-turbine gas plant type generation by 25 TWh for the year; this actual generation is nearly four times as much as the simulation shows optimal.

The data also show that combined cycle generation in the actual ERCOT market was less than simulated generation by 17 TWh, or approximately 15%.

With respect to segments, the Backcast assessment indicates that IOU units' actual generation was greater than the simulated generation by 19 TWh (17%), and IPP units' actual generation was less than simulated generation by 30 TWh (27%).

5 Implementation Impact Assessment

5.1 Purpose

KEMA was assigned to perform the Implementation Impact Assessment part of this Cost Benefit Study.

The purpose of the Implementation Impact Assessment (IIA) portion of the study was to develop detailed cost estimates of the implementation costs to change from the existing ERCOT market design (the Base Case) to each of the nodal market designs defined in three change cases. A summary of the change cases is described below.

The cost estimates provided are at a level of detail that would allow the Commission and stakeholders the necessary information to modify or delete specific items or categories of expenses as required by P.U.C. SUBST. R. 25.501.

The cost estimates provided include both the capital costs and incremental O&M only, resulting from the change in each market design. Items that are significant cost drivers are clearly identified, as are the assumptions that drive the estimates. Items that are considered to be discretionary, (that is, items with respect to which a market participant has the option to use more sophisticated tools at its discretion) have been identified, and their cost is not included in the estimates. KEMA understands that the final determination of what should constitute discretionary expenditures will be made by the Commission working with the ERCOT stakeholders. The KEMA methodology is flexible enough to permit the easy addition of any items that the Commission determines should not be discretionary as described in this report.

Cost estimates were developed for the three change cases as defined and published by the stakeholder committees. It was not in the purview of the study to comment on the market designs or change cases, but to estimate the costs for these cases. The change cases were as follows:

1) **TNT Change Case** [46] The scope and a detailed description of this change case were defined by the approved Concept (White) Papers and supported by details in the Draft TNT Protocols that were available as of June 2, 2004.

2) **Nodal Light Change Case** [47] The scope and a detailed description were provided in the Change Case Summary that was available as of June 2, 2004.

3) **Replication Change Case** [48] The scope and a detailed description were provided in the Change Case Summary that was available as of June 2, 2004.

A summary description of the change cases is provided in Appendix 5-A.

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[46] See the ERCOT public website at: ERCOT HOME > Texas Nodal Team > TNT Documents <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=45.>

[47] See the ERCOT public website at: ERCOT HOME > Texas Nodal Team > TNT Documents <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=68>

[48] See Footnote 45.

5.2 Implementation Impact Assessment Methodology

KEMA used the following methodology to determine the cost estimates for each of the change cases:

1) The concept papers were analyzed to understand the proposed changes to the market design since the protocols will not be finalized until the first quarter of 2005.

2) Existing market timeline processes were captured.

3) The changes in the market timeline activities were identified and mapped onto the market timeline for the periods such as pre-day-ahead, day-ahead, real-time, and post-day ahead.

4) The major business processes were captured.

5) An assumptions memo defining the implementation impacts was issued and reviewed at several of the Cost-Benefit Concept Group (CBCG) meetings.

6) A market participant survey was prepared and issued to all registered ERCOT market participants, requesting information regarding their systems, staffing, and role, if any, in the ERCOT and ISO New England (ISO-NE) markets. The intent of the survey was to establish a representative sample inventory of market participants' systems used in the current ERCOT market design. These inventories assisted KEMA consultants in validating their own assumptions and internal knowledge about market participants' systems.

7) KEMA conducted a series of interviews with the internal ERCOT staff to understand the existing ERCOT systems and staff as well as ERCOT's plans for new releases that would be available in the next two years. These interviews allowed KEMA consultants to raise an accurate inventory of ERCOT systems, processes, and staffing needs required to run the current wholesale markets.

8) KEMA visited ISO-NE to understand the approach used by ISO-NE when it adapted the PJM congestion management and multi-settlement systems. This visit allowed KEMA consultants to validate their Replication Change Case assumptions.

9) An impact assessment was performed for each major business process in terms of people, processes, and technology using survey results, ERCOT inventory results, analysis of the TNT change case concept papers, Nodal Light and Replication change case descriptions, publicly available information, and private KEMA internal knowledge about ERCOT and other North American energy markets.

10) Each impact was analyzed and determined to be one of the following:

    a) A modification of a simple, moderate, or complex degree of change or development effort for existing staff, processes, or technology (including systems and software), or

b) A replacement or new deployment functional deployment of a simple, moderate, or complex degree of change or development effort for new staff, processes, or technology (including systems and software).

c) An impact of "NONE" was assigned if it was determined that the change case would not require a change to the existing people, process, or technology. The key reason for the impact assessment was also captured.

11) A cost estimate was developed for each impact, taking into consideration an estimated level of effort to make the change through the change process life cycle. Based on input from CBCG, a few discretionary business processes and items were identified and estimated but not included in the final numbers. These are listed separately in Section 5.6 of this report.

12) Individual cost estimates were developed for ERCOT, QSEs (simple and complex), and TDSPs to be used in developing the costs by market segment.

13) An approximate number of market entities for each segment was determined for use in the total cost calculations. These numbers were deduced from ERCOT-provided market participant rosters, market segment membership lists, and market reports published by ERCOT.

14) KEMA documented its findings in this section of the report.

Figures 5-1 and 5-2 illustrate KEMA's methodology utilized for the implementation impact assessment process.

Figure 5-1 outlines how the data collection process was utilized to develop specific profiles and cost factors to be applied to the identified impacts.

Figure 5-1 Data Collection Process

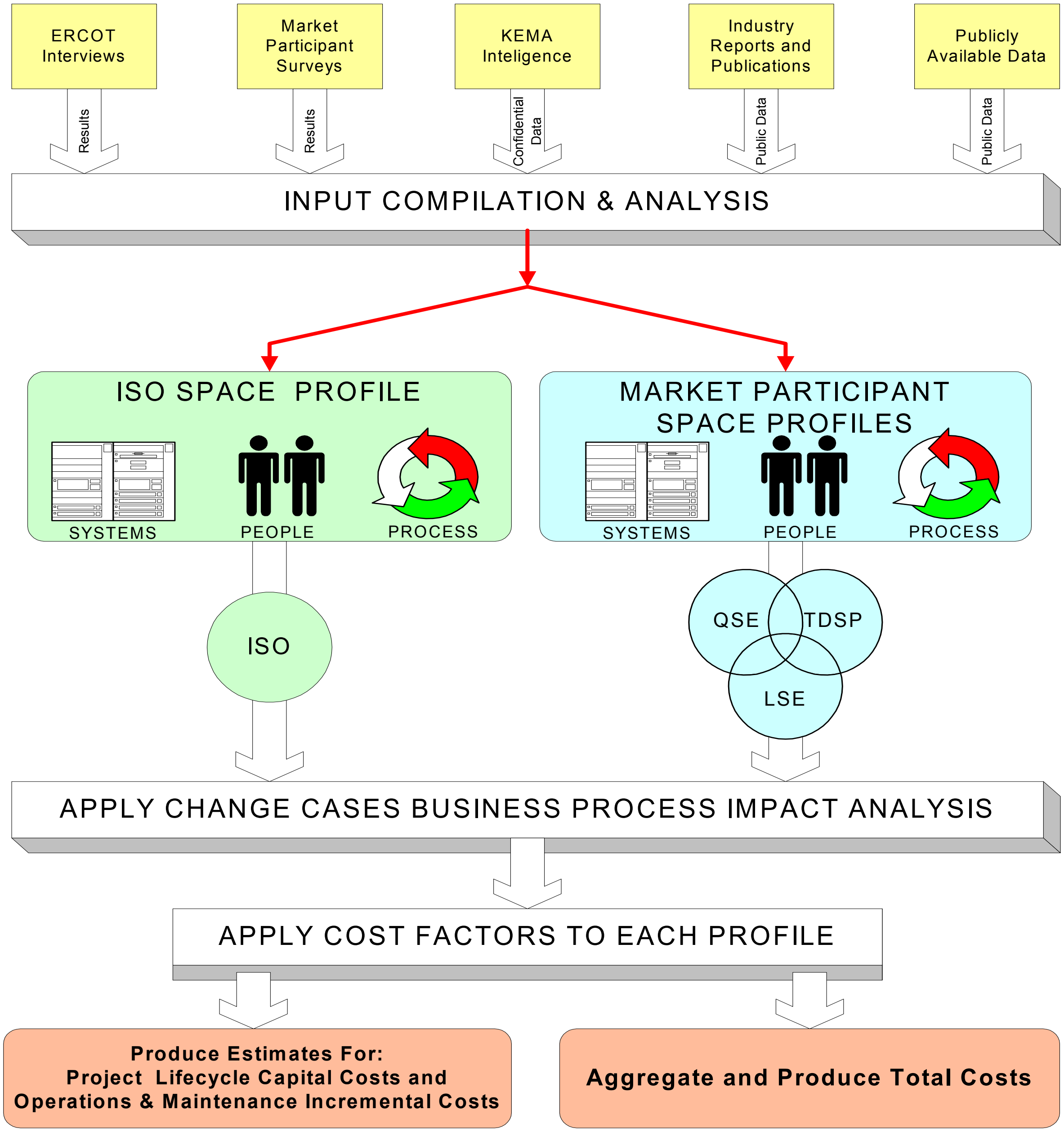
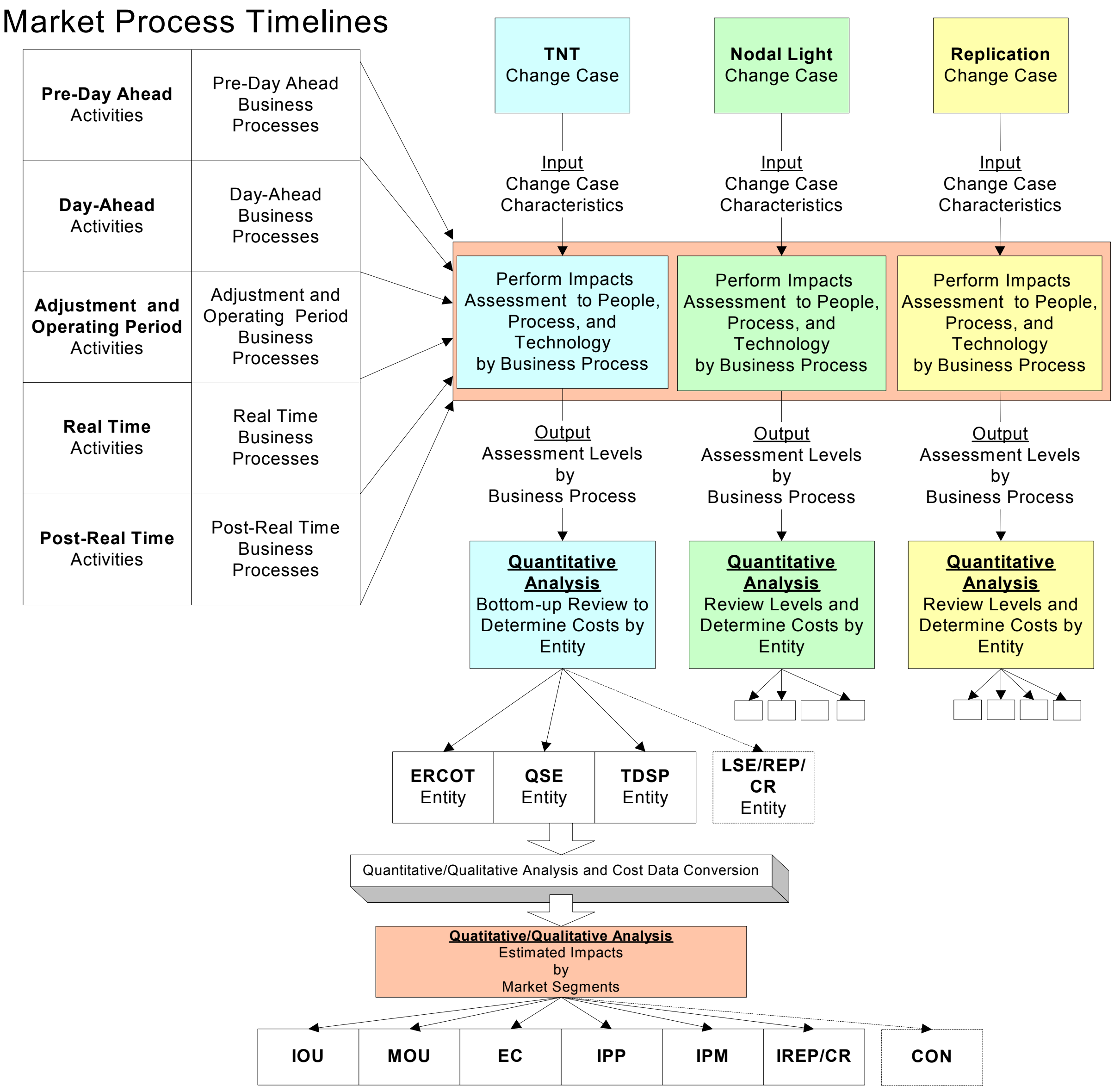

ERCOT Interviews
Market Participant Surveys
KEMA Inteligence
Industry Reports and Publications
Publicly Available Data
Results
Results
Confidential Data
Public Data
Public Data
INPUT COMPILATION & ANALYSIS
ISO SPACE PROFILE
SYSTEMS
PEOPLE
PROCESS
MARKET PARTICIPANT SPACE PROFILES
SYSTEMS
PEOPLE
PROCESS
ISO
QSE
TDSP
LSE
APPLY CHANGE CASES BUSINESS PROCESS IMPACT ANALYSIS
APPLY COST FACTORS TO EACH PROFILE
Produce Estimates For: Project Lifecycle Capital Costs and Operations & Maintenance Incremental Costs
Aggregate and Produce Total Costs

Figure 5-2 outlines how the market process timelines were utilized to perform a people, process and technology assessment to each of the three change cases and how quantitative and qualitative analysis was performed to derive the final results.

Figure 5-2 Impacts Assessment Overview


Market Process Timelines
Pre-Day Ahead Activities
Pre-Day Ahead Business Processes
Day-Ahead Activities
Day-Ahead Business Processes
Adjustment and Operating Period Activities
Adjustment and Operating Period Business Processes
Real Time Activities
Real Time Business Processes
Post-Real Time Activities
Post-Real Time Business Processes
TNT Change Case
Nodal Light Change Case
Replication Change Case
Input Change Case Characteristics
Input Change Case Characteristics
Input Change Case Characteristics
Perform Impacts Assessment to People, Process, and Technology by Business Process
Perform Impacts Assessment to People, Process, and Technology by Business Process
Perform Impacts Assessment to People, Process, and Technology by Business Process
Output Assessment Levels by Business Process
Output Assessment Levels by Business Process
Output Assessment Levels by Business Process
Quantitative Analysis Bottom-up Review to Determine Costs by Entity
Quantitative Analysis Review Levels and Determine Costs by Entity
Quantitative Analysis Review Levels and Determine Costs by Entity
ERCOT Entity
QSE Entity
TDSP Entity
LSE/REP/CR Entity
Quantitative/Qualitative Analysis and Cost Data Conversion
Quantitative/Qualitative Analysis Estimated Impacts by Market Segments
IOU
MOU
EC
IPP
IPM
IREP/CR
CON

5.3 Assumptions

KEMA prepared an assumptions memo that provided interested parties the assumptions upon which the impacts would be assessed. The entire IIA assumptions memo is provided in Appendix 5-B. The major assumptions are highlighted below.

5.3.1 Classification of Market Participants

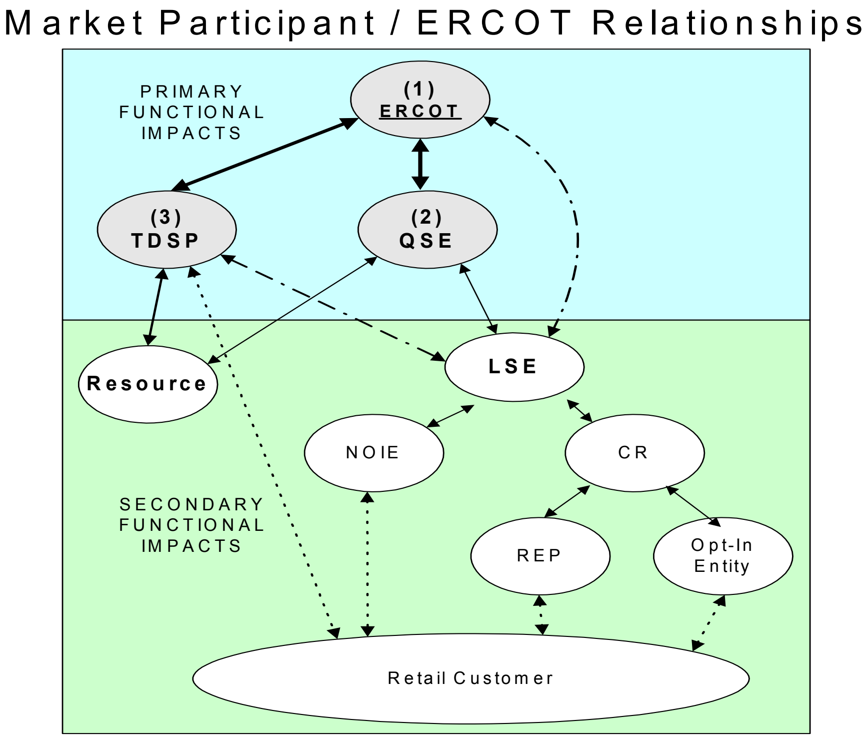
Market Participants were classified into the following Entity Types/Roles (Market Entities), which were used to compile the results of the Implementation Impact Assessment:

1) Primary Functional Impacts
   a) ERCOT
   b) Qualified Scheduling Entity (QSE)—simple and complex
   c) Transmission and/or Distribution Service Provider (TDSP)

2) Secondary Functional Impacts
   a) Load Serving Entity (LSE) (including CR/REPs and end Consumers)
   b) Resources

The basis for the Entities was derived using the Market Participant relationship/business interaction diagram shown in Figure 5-3. KEMA assumed that the current Market Participant relationships as defined in current Protocols will not change for a Nodal market.

Figure 5-3 Market Participant / ERCOT Relationships


Market Participant / ERCOT Relationships
PRIMARY FUNCTIONAL IMPACTS
(1) ERCOT
(3) TDSP
(2) QSE
Resource
LSE
NOIE
CR
SECONDARY FUNCTIONAL IMPACTS
REP
Opt-In Entity
Retail Customer

Detailed implementation costs were developed for the following Market Segments:

1. Investor Owned Utilities (IOUs)
2. Municipally Owned Utilities (MOUs)
3. Electric Cooperatives (ECs)
4. Independent Power Producers (IPPs)
5. Power Marketers (IPMs)
6. Retail Electric Providers (IREP/CR)
7. ERCOT (Including the Commission Market Monitor systems and functions)

The vast majority of implementation costs for these market segments are adequately quantified.
An additional market segment analysis was solicited in the study requirements for the Consumers market segment. The data collected throughout the duration of study could not support a quantitative treatment of this market segment. This segment did not submit valid Market Participant surveys and no independent data could be obtained from ERCOT or other interested parties. Some anecdotal information was submitted by one consumer group representative to illustrate the types of impacts their particular organization could face should the wholesale market design change to any of the nodal market change cases.

It is KEMA's experience in other markets that most individual consumers will not face any significant "implementation" costs as defined in this study. While this is KEMA's stated opinion, KEMA also recognizes that certain groups or organizations representing larger or organized consumer groups could indeed face some incremental costs in adapting their services due to market design changes. To the extent that consumers or any other third (interested) party that does not interact directly and on a daily basis with the market operator (in this case ERCOT) wants to voluntarily keep abreast of the changes and provide a better suite of services for its members, these organizations can face discretionary costs to better prepare for the change. Therefore, average basic costs for the impacts due to change management activities, following the market development activities and meetings, changes in documentation and training, etc., can be estimated at the "unit" level (per interested entity). However, propagating and allocating those costs to an unknown number population of third (interested) parties cannot be done with any certainty or without being subject to a large margin of error. KEMA has estimated those costs at the unit level but does not have enough independent data to provide an opinion on how to propagate or allocate those across the market segments.

5.3.2 Cost Assumptions

The following list identifies the major assumptions used in developing the cost estimates:

1) Only costs that could be directly attributable to changing the market design have been considered in the analysis. In similar types of situation, the work to make improvements to existing systems is done concurrently with making large changes driven by rule changes. These costs for non-TNT related improvements were not estimated.

2) The average labor rate used for non-ERCOT labor was $125,000, as determined from the State of Texas Median Salary Data (Fully Burdened) provided by Salary.com and using composite salary data from 11 relevant job types for Austin, Dallas, El Paso, Houston, and San Antonio.

3) The average O&M labor (fully burdened) rate used for ERCOT labor was $135,000, as provided by ERCOT. The monthly FTE project labor rate used in the ERCOT costs was $22,000, derived by using a 2.2:1.3 ratio of external (contracted) resources to internal resources, since ERCOT is traditionally more dependent on external resources during the project phase. This ratio is based on 2002–2003 observed costs while KEMA managed several ERCOT programs within their EMMS portfolio. It is worthwhile to note that this observed monthly project labor rate could be lowered if ERCOT is able to obtain a more favorable mix of consultants to ERCOT project staff. This is not limited to sheer numbers but their cost/value added and experience handling these types of projects. These factors will determine the appropriate mix of consultants to ERCOT project staff.

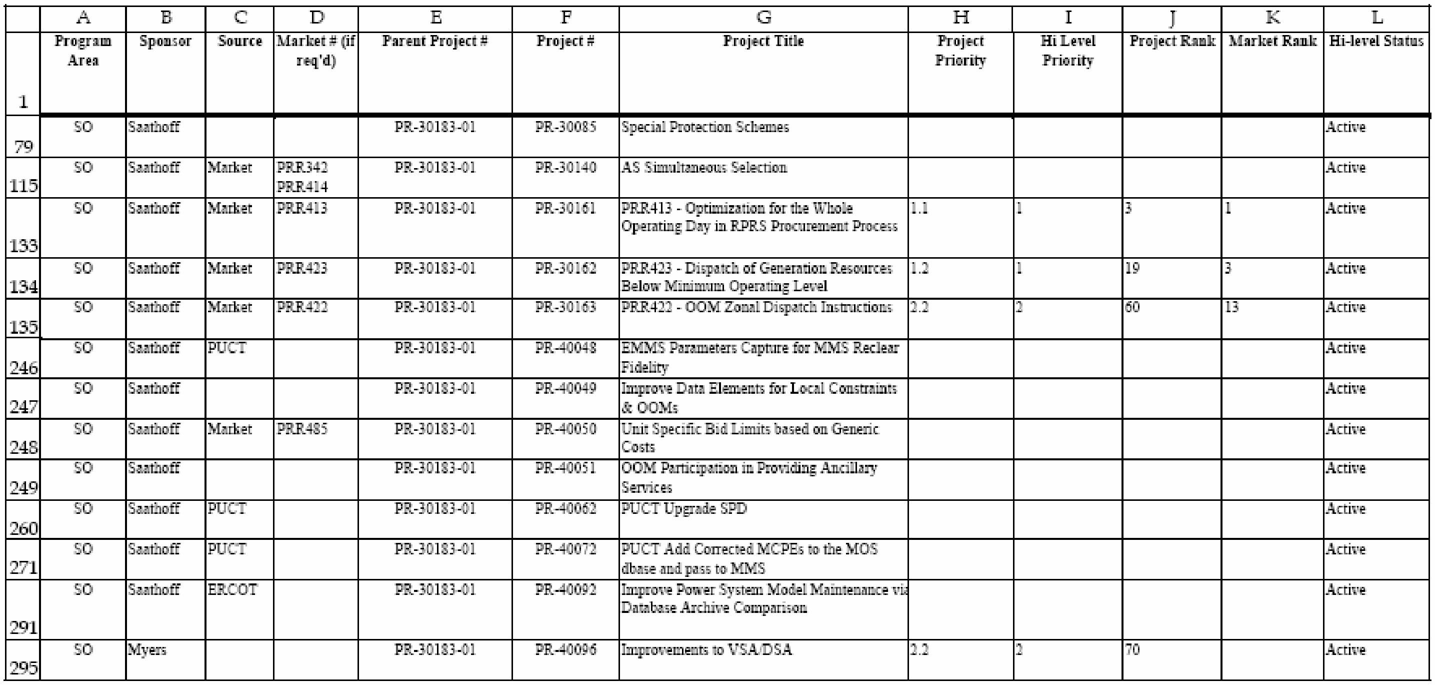
4) The CBCG facilitating team directed KEMA to consider all PRRs approved by the ERCOT Board of Directors as of March 31, 2004 as functionality and costs that would be in the existing system(s) and part of the Base Case. ERCOT's Program Management Office provided a list of approved PRRs as of March 31, 2004 pending implementation. This list is provided in Appendix 5-F.

5) As a consequence of item 4, any functionality that is going to be included in the latest plans for ERCOT EMMS releases R4 and R5 was considered as part of existing functionality and therefore part of the Base Case. ERCOT's Program Management Office provided information about their planned R4 projects and candidate R5 projects. Lists of R4 and R5 projects are included in Tables 5-1 and 5-2.

6) The Auction based Day Ahead Market (ADAM) currently under procurement was also considered to be part of the Base Case per direction of the CBCG facilitating team.

7) All TNT efforts up to the March 2005 filing were considered "sunk costs" as a result of the regulatory process to define the direction and outcome of the Texas Nodal Market re-design project. This was also done per direction of CBCG.

Table 5-1 EMMS Release 4 Planned Projects – Provided by ERCOT PMO



	A	B	C	D	E	F	G	H	I	J	K	L
1	Program Area	Sponsor	Source	Market # (if req'd)	Parent Project #	Project #	Project Title	Project Priority	Hi Level Priority	Project Rank	Market Rank	Hi-level Status
79	SO	Saathoff			PR-30183-01	PR-30085	Special Protection Schemes					Active
115	SO	Saathoff	Market	PRR342 PRR414	PR-30183-01	PR-30140	AS Simultaneous Selection					Active
133	SO	Saathoff	Market	PRR413	PR-30183-01	PR-30161	PRR413 - Optimization for the Whole Operating Day in RPRS Procurement Process	1.1	1	3	1	Active
134	SO	Saathoff	Market	PRR423	PR-30183-01	PR-30162	PRR423 - Dispatch of Generation Resources Below Minimum Operating Level	1.2	1	19	3	Active
135	SO	Saathoff	Market	PRR422	PR-30183-01	PR-30163	PRR422 - OOM Zonal Dispatch Instructions	2.2	2	60	13	Active
246	SO	Saathoff	PUCT		PR-30183-01	PR-40048	EMMS Parameters Capture for MMS Reclear Fidelity					Active
247	SO	Saathoff			PR-30183-01	PR-40049	Improve Data Elements for Local Constraints & OOMs					Active
248	SO	Saathoff	Market	PRR485	PR-30183-01	PR-40050	Unit Specific Bid Limits based on Generic Costs					Active
249	SO	Saathoff			PR-30183-01	PR-40051	OOM Participation in Providing Ancillary Services					Active
260	SO	Saathoff	PUCT		PR-30183-01	PR-40062	PUCT Upgrade SPD					Active
271	SO	Saathoff	PUCT		PR-30183-01	PR-40072	PUCT Add Corrected MCPEs to the MOS dbase and pass to MMS					Active
291	SO	Saathoff	ERCOT		PR-30183-01	PR-40092	Improve Power System Model Maintenance vi Database Archive Comparison					Active
295	SO	Myers			PR-30183-01	PR-40096	Improvements to VSA/DSA	2.2	2	70		Active

Table 5-2 EMMS Release 5 Candidate Projects – Provided by ERCOT PMO

Program Area	Source	Release	Q	start Month	Officer	Business Owner	Project No.	Project Title	Criteria Score	2005 Priority
SO	MRKT	R5 Areva	q2-q3/06	May	Jones	Mickey	PR-30018	RT Market Ramp Rate (feasability study only)	73%	1.1
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Myers	PR-30084	CSC Thermal & Volt Limits Calculations/Posting	94%	1.1
SO	ERCOT	R5 Areva	q2-q3/06	May	Giuliani/ Galvin	Ragsdale	PR-40022	Automate Sending "RMREQ's" to Lodestar	77%	1.2
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Myers/Ragsdale	PR-40087	RMR Process Automation	77%	1.2
SO	PUCT	R5 Areva	q2-q3/06	May	Jones	Tamby	PR-50003	MOMS - Enhancements to AREVA Study Tools	79%	1.1
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Myers	PR-50029	Improvements to VSA/DSA - Phase II	91%	1.2
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Myers	PR-50035	SPS Modeling Enhancements	80%	1.2
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Myers	PR-50039	EMS Archive Comparison Tool Phase II	72%	1.2
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Obadina	PR-50040	EMMS SPR Enhancements	60%	1.2
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Adams	PR-50043	Enhancement to Dynamic Rating	91%	1.2
SO	MRKT	R5 Areva	q2-q3/06	May	Jones	Patterson	PR-50046	PIP210 - For Responsive Reserve and Non-Spinning Reserve Services; PRR496 - Block Deployment (for Responsive & Non-Spin)	76%	1.3
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Saathoff	PR-50056	Entity Name Change in ERCOT Applications	59%	1.3
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Hinson	PR-50063	Local Constraint Entry Check/Validation	78%	2.1
SO	ERCOT	R5 Areva	q2-q3/06	May	Jones	Hinson	PR-50064	Identification of Spinning Reserve Deficiency	74%	2.1
SO	MRKT	R5 Areva	q2-q3/06	May	Jones	Adams	PR-50120	(SCR735) Include Hydro Units in Synchronous Condenser Mode in SPD RRS Allocation		1.3

5.4 Target Processes

The following market process timeline/business processes were identified and included in the analysis (note that not all processes apply to every market entity and these non-applicable processes are identified in the detailed impact assessment spreadsheets in Appendixes 5-C, 5-D, and 5-E):

1) Pre-Day Ahead Activities
    a) Registration
    b) Deal Capture and Contract Management
    c) Portfolio Optimization
    d) System Planning
    e) CRR Modeling and Auctions
    f) Operations Engineering
    g) Outage Coordination
    h) Operations Systems Studies
    i) Modeling and database maintenance

2) Day-Ahead Activities
    a) Load Forecast
    b) Wind Capability Forecast
    c) Studies and ADAM
    d) Studies and EHDAM
    e) Studies and IDAM
    f) A/S Scheduling
    g) A/S Procurement
    h) DaRUC
    i) Outage Coordination
    j) Operations Systems Studies

3) Adjustment Period and Operating Hour Activities
    a) Load Forecast
    b) A/S Adjustments and Scheduling
    c) Operating Hour Studies and HaRUC

4) Real-Time Activities
    a) Forced (Unplanned) Outages
    b) Load Forecast Corrections
    c) Real-time sequence and dispatch
    d) Load and Frequency Control
    e) Operator Actions

5) Post Real-Time Activities
    a) Price Postings
    b) Meter Data Acquisition
    c) Data Aggregation
    d) Load Profiling
    e) Settlements
    f) Post Settlement LMP Mitigation and Market Monitor Functions
    g) Dispute Resolution
    h) Performance Metrics

6) Corporate Activities
    a) Facilities Management
    b) Client Services
    c) HR and Personnel
    d) Credit/Risk Management.

5.5 Implementation Impact Assessment Results

The Functional Impact Assessment was based on identifying the functional impacts of each Change Case functional impact to a common Market Process Timeline for all three Change Cases. Each Market Process Timeline was broken down further into generic business processes applicable to ERCOT and each Market Entity type. Each Market Functional Timeline consisted of business processes to be reviewed and identified for impacts related to people, process, and technology. This method was used to quantify/qualify the level of impacts from the derivations of each Change Case.

The levels of impact were classified as follows:

1. None
    - None to minimum changes required. Can be absorbed by current staffing, technology, and processes.
2. Modification
    - Simple. Simple modifications to existing staffing, technology, and processes achievable through a short-term effort (1-3 months)
    - Moderate. Average complexity modifications to existing staffing, technology, and processes achievable through a medium size effort (4-9 months)
    - Complex. High complexity modifications to existing staffing, technology, and processes achievable through a large-scale effort (10-18 months or more)
3. New/Replacement
    - Simple. Simple replacements or additions to existing staffing, new technology, and new processes achievable through a short-term effort (1-3 months)
    - Moderate. Average complexity replacements or additions to existing staffing, new technology, and new processes achievable through a medium size effort (4-9 months)
    - Complex. High complexity replacements or additions to existing staffing, new technology, and new processes achievable through a large-scale effort (10-18 months or more)

The end result of this part of the analysis provided an overview of the business processes most affected by each Change Case. Most important, this also provided the next link for the quantitative estimation of the implementation costs of each Change Case (See Appendixes 5-C, 5-D, and 5-E for the detailed Impact Assessment.).

5.6 Discretionary Items

The impact analysis revealed several items that could be considered discretionary items in that it is up to the business entity to determine if they need more sophisticated applications or tools in order to execute their business and operations processes. The summary cost estimates do not reflect these items. The final determination of whether or not these items remain as discretionary items rests with the PUCT and the stakeholders.

5.6.1 Additional Telemetry

The TNT Fidelity Requirements for Transmission Modeling & Telemetry Concept Paper discusses the need for an accurate ERCOT State Estimator module as part of ERCOT's real time Network Security Analysis package that drives the Security Constrained Economic Dispatch (SCED) and the downstream LMP Calculator module. This is a solid concept accepted as valid by TNT. Furthermore and in anticipation of the changes required by ERCOT to further develop their current network model in order to support this TNT goal, the paper also requires the expansion of the observability of said model by the identification of all non-observable model areas, islands, and busses from 60kV up to 345kV. The identification of such areas will in turn drive ERCOT to require owners of those identified facilities to provide existing telemetry via available means, or to install non-existing telemetry including new RTUs, metering instrumentation equipment, and adequate telecommunications in order to deliver that telemetry to the ERCOT systems. This includes improvements in critical facilities needed for telecommunications redundancy in order to avoid critical telemetry losses for extended periods of time.

ERCOT and ROS were charged with the development of metrics, benchmarks, and a plan to identify, and recommend such facilities. ERCOT conducted a meter placement study that makes recommendations on where additional telemetry is needed. The results were published by ERCOT in the State Estimator Observability and Redundancy Requirements report to ROS dated September 7, 2004. The following is an estimate of costs to implement the recommendations in that report.

e) 138-kV substations—63 stations × 3 bays per station × \$50,000 + \$15,000 = \$9,465,000

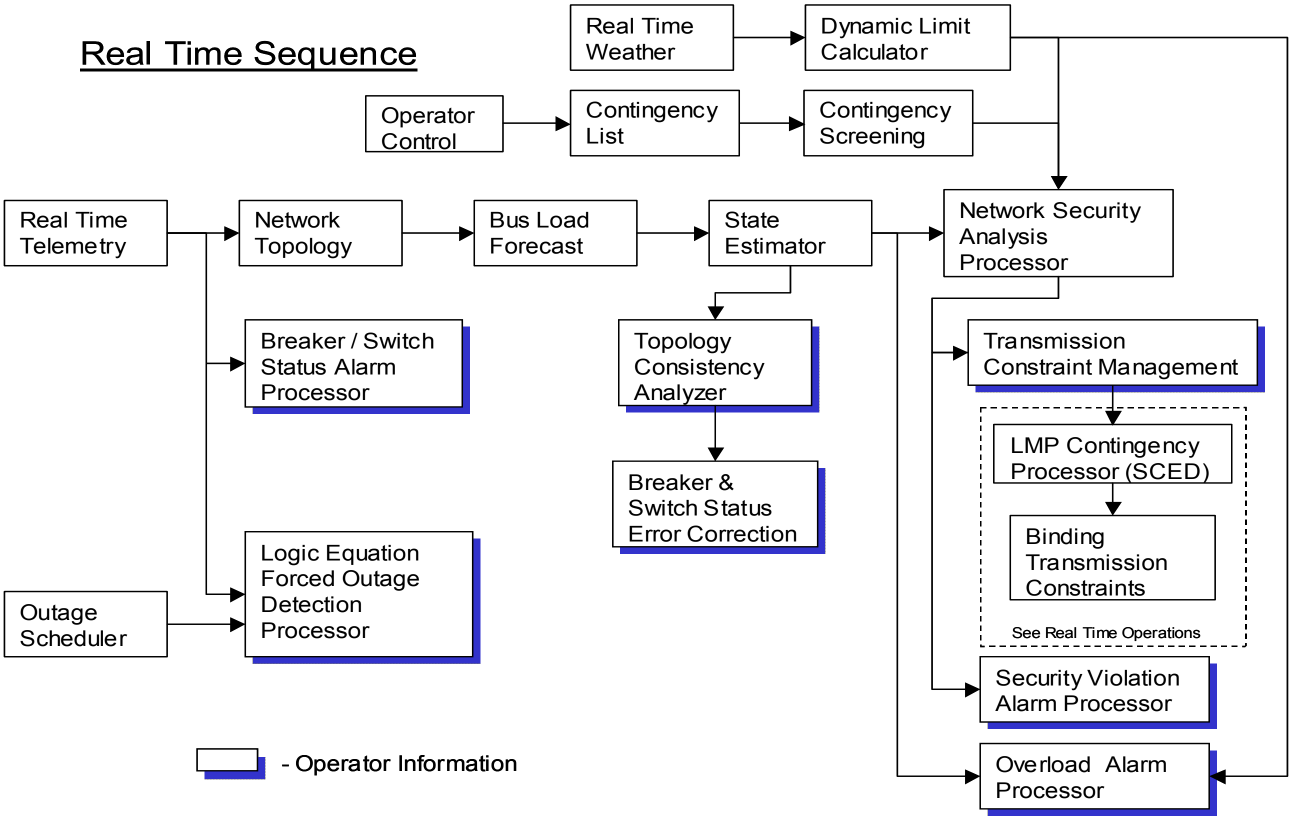
f) 69-kV substations—201 stations × 3 bays per station × \$25,000 + \$15,000 = \$15,090,000

g) Stations under 69 kV—6 stations × 3 bays per station × \$15,000 + \$15,000 = \$285,000

h) These estimates are based on the following assumptions:
   i) No new building is needed
   ii) Existing raceways have space for additional wiring
   iii) Space is available for transducers in existing panels or racks
   iv) "Last-Mile" Communications are available

It is our opinion that the existing zonal model and all of the Change Cases will benefit similarly from the additional telemetry and the added robustness of the telecommunications for existing and new telemetry. Please refer to the generic Network Security Analysis block diagram shown in Figure 5-4. Note that the Real Time Telemetry inputs occur upstream of the State Estimation and the Network Security Analysis Processor that provides the feed to the Transmission Constraint Management tools (real-time congestion) used by the real-time operator. Also note that the SCED/LMP Calculator module is downstream from this module. Any node definition or node aggregation method used for resources or loads will affect the SCED/LMP Calculator differently but the power system input from the State Estimator and Network Security Analysis is the same.

Figure 5-4 Real Time Sequence Block Diagram[49]


Real Time Sequence
Real Time Weather
Dynamic Limit Calculator
Operator Control
Contingency List
Contingency Screening
Real Time Telemetry
Network Topology
Bus Load Forecast
State Estimator
Network Security Analysis Processor
Breaker / Switch Status Alarm Processor
Topology Consistency Analyzer
Transmission Constraint Management
LMP Contingency Processor (SCED)
Breaker & Switch Status Error Correction
Binding Transmission Constraints
See Real Time Operations
Logic Equation Forced Outage Detection Processor
Outage Scheduler
Security Violation Alarm Processor
- Operator Information
Overload Alarm Processor

Given ERCOT's current level of model observability and SE accuracy, there is no clear way to separate what is a set of telemetry and telecommunications improvements that can be attributed exclusively for a nodal model improvements as opposed to a set of different telemetry and telecommunications additions that could be used today to enhance the results of the ERCOT Security Analysis and their local congestion management results. In other words, we do not have a Base Case that allows those differences to be established. Any telemetry and telecommunications additions done through appropriate engineering studies will produce equal benefits in the power flow solution obtained by ERCOT's network security analysis software for the current market design.

Given the level of ERCOT's model observability today, the current level of SE accuracy is not where it should be. It could be significantly improved through added observability. Today's market, and specifically the tools that feed the current market's Security Analysis that in turn affect how contingencies are defined and how limits on local elements are calculated, can expect to see improvement in results with additional telemetry and data reliability due to more redundancy in current telecommunications. All of these have an effect on the information available to the current real-time software and to the ERCOT operators that make local congestion management decisions on a daily basis. Therefore an unknown percentage of the added telemetry and telecommunications redundancy that ERCOT will identify and require in collaboration with ROS will serve to fix the current non-nodal model problems and the quality of the NSA solution shown to the ERCOT operators.

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[49] Extracted from the Network Analysis Concept Paper approved by the ERCOT Board of Directors on 4-20-04.

5.6.2 CRR Modeling and Auctions

Congestion Revenue Rights (CRRs) are defined as a permit that allows the holder to be compensated for the difference in price between source and sink. Each CRR is denominated in Megawatts and the holder may acquire these rights in a CRR auction, have pre-assigned rights, or purchase CRRs in a secondary market outside the auction process. A very good discussion of CRRs and processes surrounding them can be found in TNT CMCG Concept Document White Paper Congestion Revenue Rights, approved by the ERCOT Board of Directors on 5/18/2004.

The following discussion explains KEMA's rational on why we consider the CRR modeling and auction business process to be a discretionary item for both simple and complex QSEs. We offer anecdotal evidence from another auction as well as other tools available to manage delivery risk from source to sink.

From publicly available auction results for 2003 monthly auctions, Figure 5-5 depicts the megawatts with winning bids on specific congestion paths and the megawatts with winning offers on those same congestion paths.[50]

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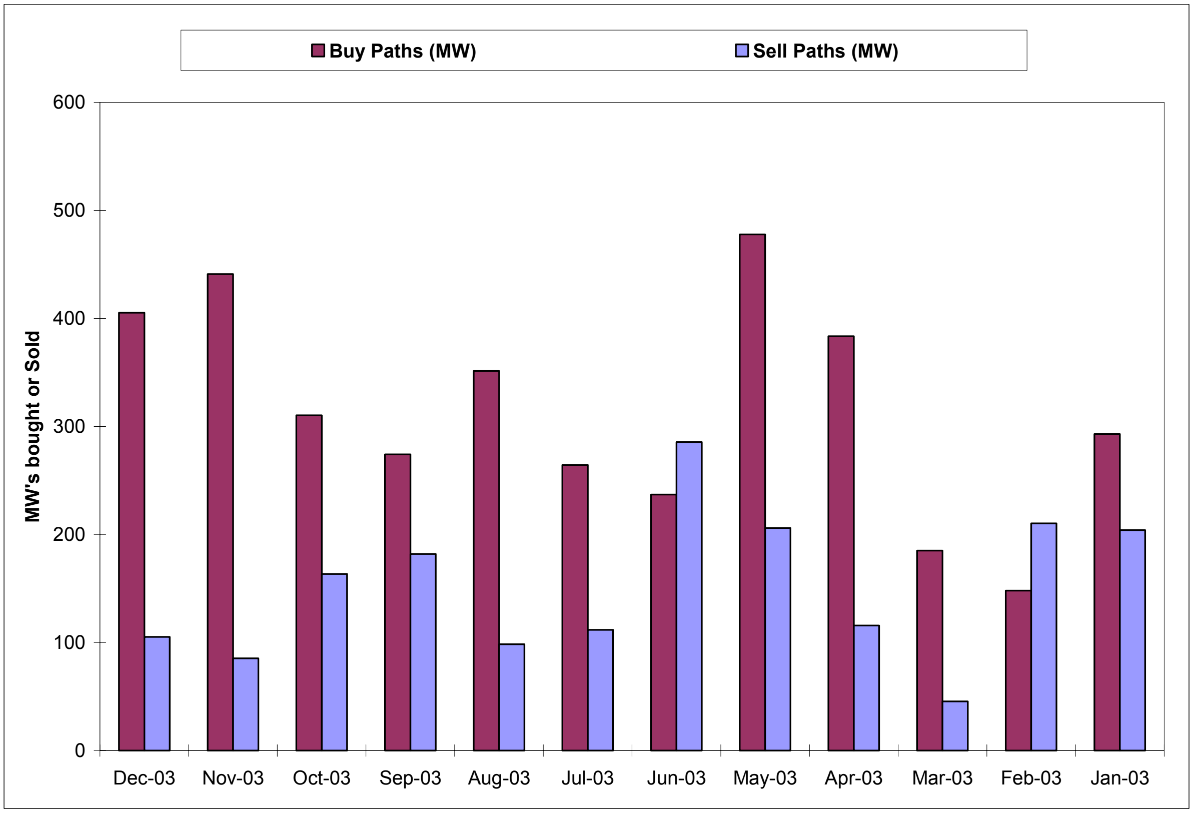
[50] All congestion permits paths sourced from APS, BGE and DPL were chosen. Segments are defined as offpeak, onpeak, and around the clock. For these paths, there can be a mismatch of buys and sells, since the auction configuration excludes grandfathered permits and may be re-configured by the ISO into other source paths equivalent to match overall auction buys and sells.

Figure 5-5 2003 PJM FTR Monthly Congestion Permit Auction Results for APS, BGE or DPL source paths and segments[51] only

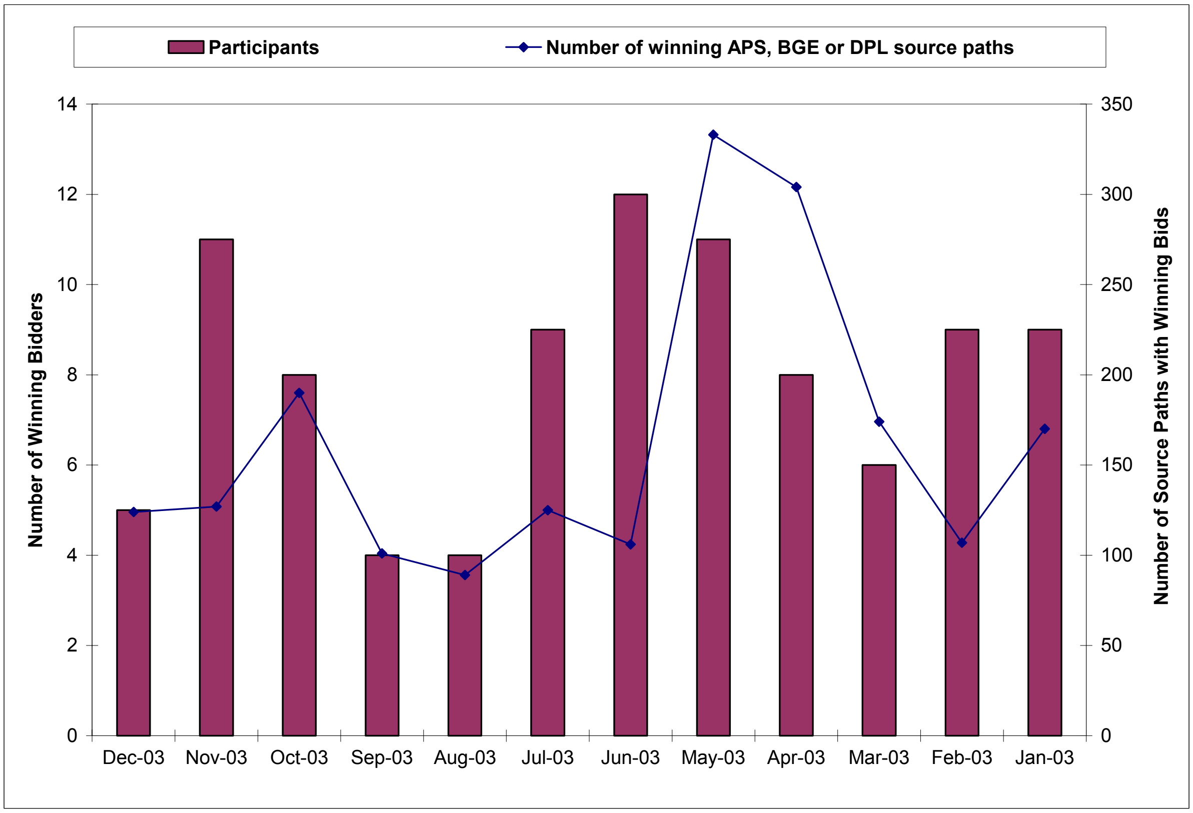


In Figure 5-6 below, the number of Participants and the winning APS, BGE, and DPL source paths and segments in the Congestion Permit Auction, the number of different winning bidders, and paths/segments with winning bids are shown for the same monthly auctions.

---

[51] Auction configuration excludes grandfathered permits and may be re-configured by the ISO into other source paths equivalent to match overall auction buys and sells.

Figure 5-6 Number of Participants and winning APS, BGE and DPL source paths and segments[52] in Congestion Permit Auction



Figures 5-5 and 5-6 indicate that participants not only varied the number of congestion paths bid in the auction, but the megawatts bid or offered over different months. The data shows that different participants emerged as winners in the monthly auctions. Obviously, there are many differences between ERCOT and PJM with respect to topology, system generation, and load demands and operations, as well as with respect to the experience of participants in the auction process itself. However, this anecdotal evidence does suggest that CRR auctions are discretionary risk management tools used by participants.

We believe that market participants will use risk management techniques, and the implementation impacts were captured within the credit/risk management business process, which is considered non-discretionary. We know that there are other mechanisms used by participants to help offset the risk of price differences between source and sink. For details on the rules associated with these tools used in other markets, please consult the appropriate ISO manuals on the appropriate ISO websites. These other mechanisms may include the following:

1) Annual auctions

2) Auction Revenue Rights or flowgate congestion permits which allow partial compensation for hedging the cost to deliver energy from source to sink

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[52] Auction configuration excludes grandfathered permits and may be re-configured by the ISO into other source paths equivalent to match overall auction buys and sells.

3) Self-scheduling that allows a participant to schedule energy to flow on a priority basis. This usually implies that the participant is willing to accept price differentials between source and sink

4) Interruptible scheduling only if there is no congestion in the day ahead markets

5) Managing the price risk of congestion in the day ahead and in the real time markets by buying (selling) in the day ahead markets and selling (buying) in the hourly markets.

5.6.3 Facilities Management for Simple Type QSEs

The costs of additional facilities assumed additional hardware and software to support a dedicated Quality Assurance system and test systems during market trials and parallel market operation. Although KEMA considers this a good practice that facilitates the change, it is also recognized that smaller participants can perform those functions without the additional expenditure.

5.7 Cost Estimates

The results of the impact assessment were used in conjunction with the following data sources as the basis for estimating the costs associated with the implementation. The cost factors were developed using the following data points:

1) KEMA Historical Knowledge Base

2) Industry Based Empirical Data

3) Industry Publications

4) Base Case Inventory results obtained from the Market Participant Survey and ERCOT interviews.

The detailed cost spreadsheets are provided in Appendixes 5-C, 5-D, and 5-E. All cost estimates should be considered to be accurate to within ±10%.

5.7.1 Cost Components

The capital costs, including all the project life cycle costs, and the incremental operations, support, and maintenance (O&M) costs were developed as part of the analysis.

5.7.1.1 Capital Cost Components

The Capital Costs encompassed all of the Project Life Cycle Costs over a three-year period and included the following components:

1) Program Management

2) Requirements Definition. This step includes analysis of the protocols to develop a detailed set of requirements that are transformed into detailed statement of work documents for the appropriate solution providers.

3) Development. This step includes requirements analysis, design (business and technical), code, and testing (unit and factory).

4) Deployment. This step includes integration, documentation, training, testing (Integration and User Acceptance), and Change Management (e.g., operating procedures and guides).

5) Market Trials. This step includes a six (6) month market trials period as prescribed in the Commission order.

6) ERCOT Contingency. A contingency amount was included based upon ERCOT's current practices and includes the following (a discussion of these contingencies is included in Section 5.8, Risks):

   a) Scope Change Percentage 5%, recommended for Project Scope Changes.
   b) Communication Percentage 5%, recommended for Team Meetings, Status Meetings, Market Meetings.
   c) Project Management Percentage 10%, recommended for Project Planning & Daily Management Activities.
   d) Rework Percentage 5%, recommended for Defect Correction Rate.
   e) Overhead Percentage 5%, recommended for Indirect Charges, occupancy, etc..
   f) Other 5%, recommended for Other unpredictable indirect charges (cost of unplanned trips, materials, etc.)

7) Market Participant Contingency. A 10% contingency adder was included in the project costs for market participant impacts.

5.7.1.2 O&M Cost Components

The O&M cost components included two major areas. The O&M costs provided are incremental in that they represent the additional costs that should occur as a result of the market change. The O&M components are the following:

1) System Support and Operation. The cost for new FTEs needed to support additional workload in the areas of corporate administration, information technology, system operations, and market operations.

2) Hardware and Software Licenses and Maintenance. The incremental costs for hardware and software license maintenance fees resulting from the change cases escalated at 1 to 2% per year.

5.7.1.3 Market Segments

Based on the total list of market participants provided by ERCOT, we were able to quantify the market segments by their relevant market entity components. ERCOT provided a list of market participants with an indication of their market segment and the market entity role that the market participant plays. Table 5-3 identifies the quantities used in the derivation of the total costs by market segment. The "No Segment" column corresponds to market entities that could not be classified into any of the other market segments due to lack of segment definition in ERCOT rosters. However, all of these "No Segment" entities could fall under the IPP, IPM, or IREP segments.

Table 5-3 Market Segmentation Quantities

	IOU	MOU	EC	IPP	IPM	IREP/CR	No Segment	Total
QSE – Complex	3	3	3	3	2	0	0	14
QSE – Simple 1	0	1	0	3	1	1	0	6
QSE – Simple 2	0	0	0	5	11	12	33	61
TDSP A	3	0	0	0	0	0	0	3
TDSP B	0	0	2	0	0	0	0	2
TDSP C	1	0	0	0	0	0	0	1
TDSP D	0	6	0	0	0	0	0	6
TDSP E	3	55	70	0	0	0	1	129
LSE	6	52	24	2	1	65	31	181
Resources	11	22	12	28	9	0	64	146

The following criteria were used to develop the classifications:

1) QSE Complex. Review of the market participant surveys revealed that at least 80 to 85% of the generation capacity was represented in the responses for entities that we classified as QSE Complex and QSE Simple 1. If the QSE represented at least 10 units, it was classified as QSE Complex.

2) QSE Simple 1. If the QSE represented less than 10 units as provided in the market participant surveys, then it was classified as QSE Simple 1.

3) QSE Simple 2. This category includes the remaining QSEs that did not respond to the market participant survey but only represent about 15 to 20% of the generating capacity in ERCOT.

4) TDSP A. The largest TDSP as defined by at least 700 buses in the network model. The source for the number of busses was the State Estimator Observability and Redundancy Requirements report.

5) TDSP B. This classification is defined as TDSPs with network models between 300 and 700 buses.

6) TDSP C. This classification is defined as TDSPs with network models between 100 and 300 buses.

7) TDSP D. This classification is defined as TDSPs with network models less than 100 buses.

8) TDSP E. This classification is for the remaining TDSPs, which can be assumed to be primarily distribution service providers.

5.7.2 Individual Costs for ERCOT and by Market Entities

Tables 5-4 and 5-5 give individual costs for ERCOT and by Market Entities. The detailed cost estimates are provided in Appendixes 5-C, 5-D, and 5-E. Table 5-4 shows the individual capital costs in terms of Net Present Value (NPV), and Table 5-5 shows the individual incremental O&M costs.

Table 5-4 Market Entity Individual Capital Costs in NPV ($K)

ID	TNT (high)	TNT (low)	Nodal Light (high)	Nodal Light (low)	Replication (high)	Replication (low)
ERCOT	70,663	55,062	66,301	51,738	67,595	52,574
QSE Complex	3,794	2,374	2,856	1,738	3,140	1,959
QSE Simple	818	425	736	374	788	402
TDSP	1,061	712	1061	712	1061	712

Table 5-5 Market Entity Individual O&M Costs in NPV ($K)

ID	TNT (high)	TNT (low)	Nodal Light (high)	Nodal Light (low)	Replication (high)	Replication (low)
ERCOT	5,642	4,702	5,615	4,713	5,642	4,702
QSE Complex	369	249	333	222	369	249
QSE Simple	111	0	111	0	111	0
TDSP	147	82	147	82	147	82

The following points are noted regarding the numbers in Tables 5-4 and 5-5:

1) ERCOT. The individual estimates for the three change cases were used as defined in the detailed spreadsheets in Appendixes 5-C, 5-D, and 5-E.

2) QSE Complex. The individual estimates for the three change cases were used as defined in the detailed spreadsheets in Appendixes 5-C, 5-D, and 5-E.

3) QSE Simple 1. The individual estimates for the three change cases were used as defined in the detailed spreadsheets for a QSE Simple in Appendixes 5-C, 5-D, and 5-E.

4) QSE Simple 2. The QSE Simple estimates were multiplied by a factored number of QSE Simple 2 market entities in order to account for minimal participation of the large number of QSEs in this category that reflect only about 15 to 20% of the total capacity. That is, each of the QSE Simple 2 quantities in Table 5-1 were factored

using a multiplier of 0.2 prior to multiplying the quantities times the QSE Simple cost.

5) TDSP A. The individual TDSP estimates for the three change cases were used as defined in the detailed spreadsheets in Appendixes 5-C, 5-D, and 5-E were used for this market entity type.

6) TDSP B. The individual TDSP estimates for the three change cases as defined in the detailed spreadsheets in Appendixes 5-C, 5-D, and 5-E were adjusted by a factor of 0.45 to arrive at the cost for this market entity type.

7) TDSP C. The individual TDSP estimates for the three change cases as defined in the detailed spreadsheets in Appendixes 5-C, 5-D, and 5-E were adjusted by a factor of 0.15 to arrive at the cost for this market entity type.

8) TDSP D. The individual TDSP estimates for the three change cases as defined in the detailed spreadsheets in Appendixes 5-C, 5-D, and 5-E were adjusted by a factor of 0.05 to arrive at the cost for this market entity type.

9) TDSP E. No impacts were identified for this market entity for any of the change cases.

5.7.3 Total Costs by Market Segment

Table 5-6 shows the total capital costs (NPV), Table 5-7 shows the incremental O&M costs (NPV), and Table 5-8 shows the total overall costs (NPV) by market segment. The detailed spreadsheets are provided in Appendixes 5-C, 5-D, and 5-E.

Table 5-6 Total Capital Costs by Market Segment in NPV ($K)

ID	TNT (high)	TNT (low)	Nodal Light (high)	Nodal Light (low)	Replication (high)	Replication (low)
ERCOT	70,663	55,062	66,301	51,738	67,595	52,574
IOU	14,724	9,365	11,910	7,456	12,760	8,119
MOU	12,519	7,761	9,623	5,801	10,524	6,491
EC	12,338	7,763	9,523	5,854	10,373	6,517
IPP	14,655	8,824	11,514	6,711	12,569	7,483
IPM	10,206	6,109	8,069	4,674	8,799	5,203
IREP/CR	2,781	1,446	2,504	1,273	2,678	1,366
No Segment	5,399	2,808	4,860	2,472	5,198	2,651
Total	143,285	99,138	124,302	85,980	130,495	90,403

Table 5-7 Total Incremental O&M by Market Segment in NPV ($K)

ID	TNT (high)	TNT (low)	Nodal Light (high)	Nodal Light (low)	Replication (high)	Replication (low)
ERCOT	5,642	4,702	5,615	4,713	5,642	4,702
IOU	1,570	1,007	1,463	926	1,570	1,007
MOU	1,262	772	1,155	691	1,262	772
EC	1,240	821	1,132	741	1,240	821
IPP	1,552	747	1,444	666	1,552	747
IPM	1,094	498	1,022	444	1,094	498
IREP/CR	378	0	378	0	378	0
No Segment	733	0	733	0	733	0
Total	13,470	8,547	12,940	8,181	13,470	8,547

Table 5-8 Total Overall Costs by Market Segment in NPV ($K)

ID	TNT (high)	TNT (low)	Nodal Light (high)	Nodal Light (low)	Replication (high)	Replication (low)
ERCOT	76,305	59,764	71,917	56,451	73,236	57,276
IOU	16,295	10,371	13,372	8,382	14,330	9,126
MOU	13,782	8,533	10,777	6,493	11,787	7,263
EC	13,577	8,584	10,665	6,595	11,613	7,338
IPP	16,206	9,571	12,957	7,378	14,120	8,230
IPM	11,300	6,607	9,090	5,118	9,893	5,701
IREP/CR	3,159	1,446	2,881	1,273	3,055	1,366
No Segment	6,132	2,808	5,593	2,472	5,931	2,651
Total	156,755	107,684	137,243	94,162	143,965	98,950

5.7.4 Qualitative Analysis

Table 5-3 defined the makeup of the market segments by market entity types. Each segment includes both LSEs and resources (except IREP/CRs). When performing the impact analysis, it was determined that mandatory LSE costs were accounted for in the QSE costs with the exception of project support/change management issues such as some level of training and support. We believe these types of cost may also apply to some IREP/CRs and Consumers, as described in Section 5.3.1. A generic estimate for these costs could range from $75,000 to $250,000 per year based upon individual and company variables such as knowledge of LMP-based markets, contractual relationships with QSEs or other market players, degree of active participation in the ERCOT market, etc.

5.8 Risks

KEMA has identified the following potential risks:

1) ***Price Risk***. The estimates provided were based on a thorough analysis of the impacts on the people, processes, and technology to change the current market design to market designs defined in the change cases. In any complex project, the risk to changes in the price is apparent. The significant price risk factors that may influence the estimates provided are the following:

    a) Market Rules Under Discussion. If there are too many open issues with the rules, it will most likely increase the cost of implementation. Changing rules typically results in rework and scope creep that results in additional costs. The estimates provided have incorporated a contingency for scope creep to try to account for some changes in the rules that may not be finalized at this time.

    b) Ill-defined Requirements. If the system requirements are not well defined or are vague or ambiguous, the potential for misinterpretation of the requirements or unmet expectations increases. Developing well-defined requirements upon which the system modifications can be done or new applications can be procured can mitigate this factor.

    KEMA used the contingency factors that were provided by ERCOT as part of their planning process. Given where the stakeholder process is in determining the final market design as defined by the protocols, we believe that this is a reasonable contingency in arriving at the cost estimate. However, the critical first phase in the project should be a comprehensive planning effort and requirements analysis to be used to finalize a budget. Additional items such as developing a procurement strategy during the planning activity can also help to tighten the actual contingency that would be included in the project budget.

2) ***Execution Risk***. The estimates provided were based upon the project schedule that would meet the operational date defined by the Commission. Execution risk is directly related to project management activities. Potential schedule delays due to insufficient program and project planning can increase the execution risk and project cost. It is important to note that this would not only impact ERCOT but many of the market participants as well. Manageable schedules, meaningful project plans, and coordination between the business users, IT, and stakeholders are critical to managing this risk.

3) ***Implementation and Integration Risk.*** The interaction of systems and applications from different vendors performing the different business functions is almost always a significant risk factor. Coordination between market operations and commercial operations is critical to ensuring that this risk is reduced. Strong vendor management and internal decision-making are necessary to help reduce this risk.

6 Other Market Impact Assessment

6.1 Overview: Background and Approach to the Other Market Impact Assessment

This section presents the analysis and results of the Other Market Impact Assessment (OMIA) element of the ERCOT Cost-Benefit Study. The study examined the costs and benefits of the Texas Nodal Model (TNM) relative to the Texas Zonal Model Base Case (Base Case). The other two forward-looking elements of the Cost-Benefit Study, the Energy Impact Assessment (EIA) and the Implementation Impact Assessment (IIA), provide a quantitative analysis of those costs and benefits. The objective of this report, and of the body of the work that constituted the OMIA, is to present a qualitative assessment of those aspects of the market design changes not analyzed quantitatively in the other two elements.

The April 2004 Texas Nodal Team white papers provided the basis for identification of the market design changes that were to be considered in the OMIA[53]. The June 4, 2004 draft Texas Nodal Model protocol changes were relied upon to identify the specific potentially significant design changes associated with the implementation of a nodal design in ERCOT. Other ERCOT and industry documents used to supplement the analysis are listed in the Additional References Section and are posted on the ERCOT website.[54]

All of the proposed design changes were considered in conducting the initial stages of the OMIA. Those changes that were believed to create relatively insignificant impacts were dropped from further analysis, while the design changes that were believed to have possibly significant Commercial Impacts were grouped into eight categories of Significant Design Changes and are discussed in this report.[55] The existing protocols and the Protocol Revision Requests as of March 31, 2004 were reviewed to define the Base Case design.

The categories of Significant Design Changes associated with the TNM are as follows:

1. Real-Time Market: Resource Deployment on a Nodal Basis
2. Real-Time Market: Settlement Given Nodal Prices
3. Congestion Revenue Rights
4. Pre-assigned Congestion Revenue Rights
5. Reliability Unit Commitment
6. Modeling Details and Requirements
7. Outage Scheduling
8. Enhanced Hybrid Day-Ahead Market

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[53] Note that the May 2004 white papers did not include treatment of market mitigation. Thus, while market power is occasionally addressed in this analysis, a rigorous treatment of market power and market mitigation is not part of the OMIA.

[54] At <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=76&b=>.

[55] For example, changes such as those proposed for the details and timing of day-ahead scheduling will clearly have some impacts, but these were not considered to be commercially significant. And to the extent that manpower or software impacts are associated with such changes, those impacts are captured in the IIA.

The Auction Day-Ahead Energy Market (ADAM) was excluded from the OMIA analysis.
The implementation of ADAM is already under way and is expected to be completed regardless of the status of the Texas Nodal Case. ADAM is therefore considered to be part of the Texas Zonal Model Base Case.

The ongoing changes to the ERCOT ancillary services markets are also considered to be part of the Texas Zonal Model Base Case. Discussions with members of the Texas Nodal Team indicated that under the TNM, ancillary services will continue to be procured on an ERCOT-wide basis and that no deliverability or transmission reservation issues are associated with the deployment of ancillary services. Given that development of a simultaneous ancillary services market design is already under way, and given the lack of relationship of the ancillary services markets to nodal or locational issues, there are no apparent significant linkages between the ancillary services changes and the TNM design for the purposes of the OMIA analysis. Explicit analysis of the ancillary services markets is therefore generally excluded from this analysis. Impacts on ancillary services arising from other market features are addressed in other sections of this analysis as appropriate.

Based on initial proposals for the impacts to be assessed in the OMIA, and after a preliminary consideration of the potential impacts of the Significant Design Changes on ERCOT and the market participants, TCA grouped the potential OMIA impacts into nine categories of C*ommercial Impacts*, which are listed and briefly described in Table 1.

The report assesses the direct and indirect Commercial Impacts of each Significant Design Change as discussed under *General Approach to Assessing Impacts*, below. The indirect Commercial Impacts were assessed by considering a set of fifteen *Basic Attributes* (e.g., volatility, transparency, liquidity, and complexity) and the subsequent impacts of those Basic Attributes on the Commercial Impacts. The Basic Attributes are presented in Table 2.[56] Note that Tables 1 and 2 were developed for purposes of structuring the analysis. The analysis indicated that some of these variables were more relevant than others, and at times some Attributes or Impacts collapsed into one related type of impact. The balance of this report presents those impacts found to be relevant. Tables 1 and 2 are provided primarily for the reader's background.

Figure 6-1 shows the relationship between the Significant Design Changes, the Basic Attributes, and the Commercial Impacts.

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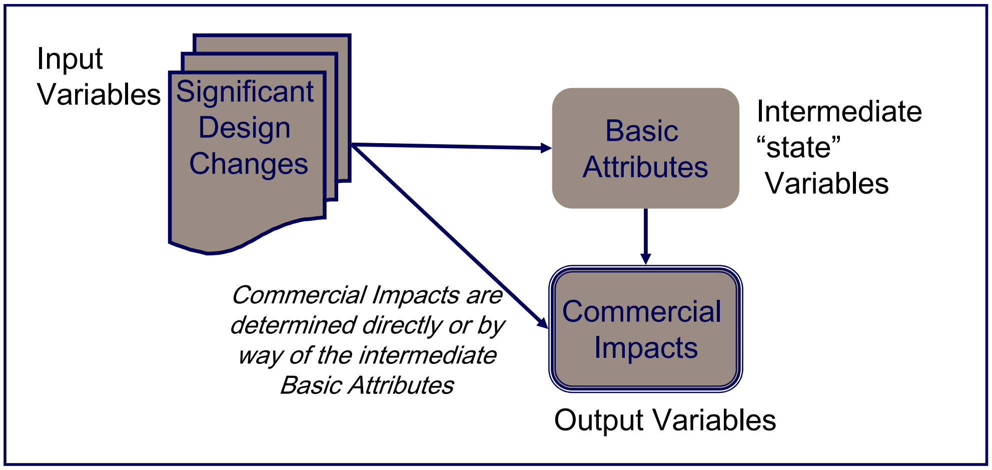
[56] There is acknowledged overlap between some of the Basic Attributes. There was no need to precisely define a mutually exclusive set of Basic Attributes, because they were simply used as tools to help in assessing the nature of the various impacts that a Significant Design Change might create. Additionally, not every Basic Attribute is relevant to every Significant Design Change, nor need it be.

Figure 6-1 Relationship of OMIA Study Elements


Input Variables
Significant Design Changes
Basic Attributes
Intermediate "state" Variables
Commercial Impacts
Output Variables
Commercial Impacts are determined directly or by way of the intermediate Basic Attributes

We note that some of the Commercial Impacts associated with the TNM's Significant Design Changes are subtle, particularly when compared with the Commercial Impacts that have been identified when assessing the impacts of transitioning from an environment without a Regional Transmission Organization (RTO) to an RTO environment. In the non-RTO/RTO analysis there are much more significant qualitative Commercial Impacts in the areas of development of competitive markets, increasing the efficiency of dispatch and system expansion, reducing discrimination, and reducing the potential for exercise of market power. In the TNM analysis, some of the Commercial Impacts are more subtle and often compensate for one another.

General Approach to Assessing Impacts

Once the structural methodology was developed, and the Significant Design Changes and the potential Commercial Impacts identified, TCA developed assessments based on a variety of information and factors. TCA reviewed third-party sources to examine the impacts of various design elements in several markets, primarily ERCOT, PJM, the NY ISO, and ISO-NE. This review identified both positive and negative impacts associated with design elements in the ERCOT zonal model as well as in the PJM, NY ISO, and ISO-NE nodal markets. In addition, TCA collected information directly from staff at ERCOT, PJM, and ISO-NE. Finally, TCA considered feedback provided by ERCOT stakeholders. Where impacts described herein are driven by third-party characterizations of market characteristics, the source of such information is provided.

TCA relied on the experience of its consultants working with ISO/RTO markets throughout North America as to market characteristics and impacts on market participants, including TCA's clients and other participants with whom the consultants interact. Many of the impacts suggested by TCA in this OMIA are based on logical analysis of the particular Change and Type of impact, and in those cases this OMIA tries to capture that logic. In other cases, impacts described herein may simply be based on a general belief on the part of one or more TCA consultants, and there has been an effort to indicate when this is the case.

Cautions

The structure of this OMIA lends itself to rigor and, more importantly, to rigorous critique. However, as with any qualitative analysis, it is also subject to certain inherent weaknesses. Three of these should be noted in particular.

- Caution 1—Forests and Trees. One significant unintended result of the OMIA structure arises from assessing each Significant Design Change individually. This approach, especially given qualitative treatment, evaluates some types of impacts separately from other impacts associated with the Change and thus does not provide a relative comparison of benefits and impacts. A simple example demonstrates this point.

  Suppose an eBay[57] user sets out to assess the costs and benefits of eBay on their life. (Of course this is easier to do after the fact than a priori, as is being done with the TNM part of the cost-benefit analysis—See Caution 2.) eBay offers liquidity benefits that garage sales or classified advertisements cannot offer. Certainly we would record for eBay positive impacts in the areas of liquidity and economic efficiency. At the same time, with respect to administrative burden, we may have to say that eBay does have some transaction costs. Overall, over the entire market place, there may be reduced transaction costs. However, for many sales the transaction costs are positive, and probably higher than they would be under the alternatives.[58] In such cases the OMIA might say that eBay has adverse impacts on administrative burdens. Someone who looks at the outcome with respect to this one measure might conclude that the eBay OMIA consultant had assessed eBay as “bad,” which is of course not the case.

  This one Commercial Impact, in isolation, has indeed been judged as adverse. And yet other measures may produce positive impacts that outweigh that adverse impact. (Certainly, we essentially know this to be true with eBay, given the continued willingness of parties to participate in that market.) The caution, then, is not to interpret a particular adverse Commercial Impact as suggesting that the Change in its entirety is adverse, or—for that matter—that the entire market design (zonal or TNM, as the case may be) is regarded as having adverse impacts. At the same time, an appropriate role of the OMIA is to go beyond stating conclusions (such as “eBay seems good overall because people use it”) by identifying possible second-order impacts, even if minor—especially if the upsides benefit one user class while the downsides impact a different user class.

- Caution 2—A Priori vs. After-the-Fact Comparison. The zonal model Base Case has been implemented in ERCOT and is now operating; the implementation of the TNM in ERCOT is being considered. The challenge of the OMIA is to compare the key design elements of each model for ERCOT in an “apples-to-apples” manner. Strictly speaking, that cannot be done. One could attempt to do so by limiting the comparison to the conceptual level. However, that approach would be unnecessarily limited since empirical evidence is available for the zonal model in ERCOT specifically, as well as for the ISO-NE and the California ISO zonal models more generally, and for the nodal model in PJM, the NY ISO, and ISO-NE. That evidence provides insights on the practical aspects of implementing the nodal model in ERCOT. Thus the OMIA assesses the impacts based upon actual experience with the zonal model in ERCOT, with the nodal model elsewhere, and with ISO-NE's recent movement from zonal to nodal. The OMIA also assesses design features that have not been implemented anywhere. It compares these categories of changes and impacts recognizing that one cannot know with certainty the actual outcome of implementing a new market design in a particular system. Yet one cannot ignore or discount impacts that have been experienced elsewhere. The OMIA tries to treat both of these types of impacts. The reader is cautioned to recognize the distinction between the two and not to expect them to be treated in comparison easily and cleanly.

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[57] An electronic exchange that has grown hugely over the past few years and offers trading a wide variety of goods (<www.ebay.com>).

[58] Where else, for example, would one offer to sell used children’s pajamas at a clearing price of $3.50 net (of shipping cost) revenue to the seller? Before eBay, the pajamas would likely have been picked up by a local charity.

- Caution 3—Whole is Greater than Sum of Parts. Although each Change and its associated Commercial Impacts are discussed individually, it is important to note that most of the TNM design elements are interrelated. The individual assessments are provided simply to support rigorous treatment, reader assessment, and future robust dialog. TCA believes that this approach was necessary to manage the comparison and assessment and that it provides some useful structure for dialog on matters which participants care about or believe but might not otherwise have distinguished. Yet it comes at the cost of losing sight of the synergies of the components, especially with respect to the TNM, where one of the main themes is movement to a more centralized and optimized system. An effort is made herein to points at which the whole can be expected to be greater than the sum of the parts. But, again given qualitative treatment, it is not easy to add individual results to get an overall "answer," nor is it likely that the parts are additive in a linear way.

Readers are encouraged to keep these cautions in mind throughout the report.

Outline of Balance of the Other Market Impact Assessment

The balance of the OMIA is structured as follows:

- Section II provides a narrative analysis for each of the Significant Design Changes associated with the TNM. Each narrative includes a brief description of the aspects of the design change that are pertinent to the OMIA and a discussion of the OMIA-related Commercial Impacts of the design change.
- Section III discusses the OMIA from the perspective of the market segments and regions.
- Section IV discusses the Other Market Impacts associated with two alternative Change Cases, the Replication Change Case and the Nodal Light Change Case. These impacts are discussed with respect to the TNM, because that is a more meaningful basis for comparison than is repeating individual comparisons with the Base Case.[59]

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[59] Note that the ultimate desired output of the Cost-Benefit Analysis may be a comparison of the TNM design to the Base Case design, the Replication Market Alternative to the Base Case design, and the Nodal Light case to the Base Case design. However, given that the OMIA-related differences between the three change cases are minor, it is much more comprehensible to present the TNM-to-Base Case comparison and then to compare the Replication Change Case and the Nodal Light case with the TNM.

Table 6-1 Commercial Impacts

Commercial Impact	Illustrative Description
1. [Facilitate Development of] **Competitive Markets**	Does the Significant Design Change facilitate or hinder competition or market penetration (the ability of new retailers to compete for load)—for example, through complexity, volatility or cost shifting?
2. [Minimize] **Discriminatory Environment**	Does the Significant Design Change reduce perceived or actual barriers that unduly discriminate against small/large players, non-incumbents, etc.?
3. [Increase] **Efficiency of Production**	Does the Significant Design Change encourage the efficient use (dispatch, commitment) of existing facilities and/or promote economic efficiency in the consumption of electricity? (This considers microeconomic principles and also incorporates maximization of social welfare—the sum of consumer and producer surplus.)[60]
4. [Promote] **Efficient Resource Expansion**	Does the Significant Design Change provide proper incentives for resource investment (including Distributed Generation and Demand-Side Management)? This includes the need for site-specific pricing and resource siting signals, and changes in risk and/or uncertainty associated with nodal pricing.
5. [Promote] **Efficient Grid Expansion**	Does the Significant Design Change encourage or discourage investment in the grid by various entities? At the right locations? With the proper trade-offs between wires and resources/Demand Side Management?
6. [Reduce] **Opportunities to Exercise Market Power**	Does the Significant Design Change increase or decrease the need for mechanisms to mitigate potential abuse of market power?
7. [Enhance] **Grid Reliability**	Does the Significant Design Change recognize the physical realities of the grid, reduce burdens on grid operators, and reduce the potential for (uneconomic) loss of load?
8. [Facilitate] **Ability to Conduct Business**	Does the Significant Design Change make it easier for entities to participate in the ERCOT market?
9. [Minimize] **Costs and Administrative Burdens**	Does the Significant Design Change reduce or increase costs (that are not already accounted for in the IIA) and burdens on market participants and on ERCOT?

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[60] Note that this metric, as described, reflects Social Welfare generally. However, various impacts tend to affect producer surplus or consumer surplus. Given that which of these may be impacted may be relevant to various stakeholders (and it is not the consultant's role to judge the merits of how the social welfare is experienced), the discussions within the text identify, where possible, how the efficiency gains are expected to be experienced (for example, when Load Serving Entities are better off).

Table 6-2 Basic Attributes of the Market Design Model

Basic Attribute	Illustrative Description
1. **Practicality** [of the resulting system]	Is the model manageable or is it too complex? Is the resulting system practical? Does it constitute sound public policy?
2. **Transparency** [of the resulting system]	Is the model and its results understandable to market participants? Are data and models available to market participants? Can the market participants verify the models and results? Can they use the models for business planning, investment decisions, projections, and analyses?
3. **Veracity** [of the resulting system	Are the results consistent with ideal market outcomes? Or are they theoretically efficient but in actuality inefficient (for example, based on data or model assumptions that do not reflect reality)?
4. **Consistency** [of the resulting system] **with Economic Principles**	Does the model provide appropriate short- and long-term price signals? Are these signals consistent with one another? Does the resulting model create the right incentives for proper market participant behaviors?
5. **Complexity** [of the resulting system]	Additional complexity generally introduces challenges to the efficient operation of markets, creates barriers to participation, etc. Is there unnecessary complexity in the model?
6. [Impacts of the resulting system on the] **Need for Non-Market Solutions**	Does the model reduce incentives for destructive gaming? Does it impact the need for Reliability Must Run (RMR) and administrative pricing?
7. **Price Transparency** [of the results]	Are market results clearly evident? Somewhat related to transparency, veracity and complexity of the model—but here the focus is on the resulting prices, schedules, and dispatch orders.
8. **Volatility** [of the results]	Does the model increase or decrease the natural volatility of the results?
9. **Ability to Hedge Risk**	Does the model offer the ability to hedge risk on both short- and long-term costs? (Note: potentially large impacts for resource expansion.)
10. **Liquidity**	Does the model result in a more or less liquid market for energy, transmission rights, ancillary services, etc.?
11. **Equity**	Are the outcomes more or less “fair”? (The perception of equitable pricing and access impacts acceptance and whether model will be stable or pressured to change.) Related to Regulatory Risk and to Cost Shifting.
12. **Cost Shifting**	Does a proposed change result in cost shifting (whether or not it is equitable)? This attribute includes the shifting of burdens related to creditworthiness and the risk of default by market participants.
13. **Regulatory Risk**	Are the market rules (for access, rights, etc.) predictable and stable? Regulatory risk attribute encompasses the risk that the market rules will be changed (often because of lack of broad acceptability to one or more groups of market participants). Increases costs of doing business.
14. [Other Impacts on the] **Costs of Doing Business**	Does the model reduce potential flexibility for market participants, resulting in reduced efficiencies? (Not intended to capture issues included in the IIA.)
15. [Other Impacts on] **Accessibility to all Market Participants**	Complexity, etc. increase barriers for participation by smaller entities.

6.2 Other Market Impact Assessment of the Texas Nodal Model

This Section presents the OMIA descriptive analysis of impacts for each Significant Design Change (Change).

Change 1. Real-Time Market: Resource Deployment on a Nodal Basis

This Change and Change 2 (Real-Time Market: Settlement on a Nodal Basis) are closely related, and the Change 1 dispatch is required for the Nodal Pricing of Change 2.

Change 1 focuses on the *operational changes* associated with the implementation of real-time dispatch of resources on a nodal basis. The most significant OMIA-related impacts of these design changes are related to (1) ERCOT's real-time deployment of resources, on a unit-specific basis, using Security Constrained Economic Dispatch/Load Frequency Control (SCED/LFC), (2) the changes that node-specific marginal pricing might cause, and (3) the proposed node-specific penalties for Uninstructed Deviations.[61]

Real-time resource deployment using SCED/LFC

Perhaps most attention associated with ERCOT's TNM has been focused on improving resource deployment. Conceptually, a zonal model with unit-specific intrazonal congestion management could result in the same, or a similar, real-time dispatch as a Locational Marginal Pricing (LMP)-based model. (This conceptual comparison was the focus of the EIA.) However, three design characteristics specific to the ERCOT zonal market cause the dispatch under the current market design to be economically inefficient.[62] These characteristics may also affect other aspects of the ERCOT market, such as ancillary services. We discuss each of these characteristics in turn below.

- Lack of Unit-Specific Bid Characteristics (i.e., Portfolio Bidding)

  The current ERCOT market design allows for the submission of schedules and bids on a portfolio basis. To the extent that the schedules and bids of several units are combined into one portfolio by a Qualified Scheduling Entity (QSE), ERCOT is not given unit-specific information for the units in that portfolio. Because ERCOT operators are required to estimate the specific operating point of units within the portfolio, ERCOT's real-time deployment is based on these estimates, and this results in inefficiencies and requires ERCOT to make frequent incremental adjustments based on SCADA data. In addition to those inefficiencies, the actual system flows can differ significantly from those predicted on the basis of ERCOT's estimated disaggregation of each portfolio. The QSE representing the portfolio must also present a single set of operating characteristics for all the units in the portfolio. The logical conclusion is that the QSE's portfolio ramp rates and other characteristics will be either too conservative or otherwise prohibitively limiting. That in turn might cause QSEs to not offer certain capacity to the Balance Energy market.[63]

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[61] There are many other operations-related changes that will not result in significant Commercial Impacts (for example, changes in deadlines for submitting Current Operating Plans) or should not result in significant Commercial Impacts if they are properly implemented (for example, ensuring that market participants whose resources are redispatched on a five-minute basis will be made whole when payments are averaged to a fifteen-minute basis). These types of change were screened out during the earlier stage of the OMIA.

[62] Note that some of these current market design characteristics were part of the analysis in the EIA and some were not. For example, aspects of the portfolio bidding such as the use of average shift factors and the reduction in the CSC interface limit to an "operational limit" were part of the impacts measured in the EIA. Similarly, the OOME structure was represented in the EIA. Other aspects of portfolio bidding could not be captured in the EIA and are presented here.

In the nodal Change Case, however, each unit scheduled or bid into the ERCOT markets is represented individually, with individual operating characteristics such as heat rates and ramp rates.

- Lack of an Efficient Commitment Mechanism[64]

From a broad perspective, the zonal Base Case offers no forward commitment process in which commitment and dispatch decisions can be jointly optimized. Further, it would not be feasible to implement a forward commitment process while the energy market continued to operate on a portfolio basis, given that much of the commitment need has locational requirements.

ERCOT also lacks an effective automated process for commitment for real-time energy needs. ERCOT's Replacement Reserve Service (RPRS) algorithms were not adequately optimized to produce effective multi-hour results, and the results historically have not directly been used to perform commitment decisions. New commitment algorithms being implemented at ERCOT are aimed at providing this optimal commitment functionality. However, to the extent that forward markets continue to be portfolio based and OOM payments are made to compensate generators for locational capacity committed by ERCOT for real time, there will be mechanisms and incentives that do not promote efficient commitment. In the absence of a centralized commitment process integrated with energy market deployments, commitments are likely to be suboptimal, and individual participants are likely to overcommit (Potomac Economics 2004, p. 17).

The TNM, as currently designed, will not immediately solve these commitment issues. The Reliability Unit Commitment (RUC) process will help ensure that commitment occurs locationally where it is needed. Further, nodal pricing will remove some incentives for overcommitting. However, the market structure will not ensure that resources are not overcommitted for other reasons (e.g., because of decisions by individual QSEs that are suboptimal over the entire market). The Enhanced Hybrid Day-Ahead Market (EHDAM) provides the opportunity for more optimal unit commitment. Given that EHDAM is intended to be implemented a year after the opening of the TNM, it is assumed that the TNM generally will offer commitment benefits.

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[63] Take, for example, the case of gas turbines that have minimum start-up and run time considerations much different from other resources and are therefore not offered into the market. (See, for example, the discussion in the 2003 SOM Report, p. 90.)

[64] Note that this issue of Commitment aligns at a high level with the RUC Change discussed later. However, given that the commitment can influence the efficiency of the deployment, it is also raised here.

- Deployment on 15-Minute Intervals

  Under the current market design, the combination of 15-minute deployment, a 10-minute notification requirement, and communication using the XML interface, Balancing Energy deployment decisions must be completed approximately 15 minutes prior to the dispatch interval. This means that the current Balancing Energy market requires more regulation and experiences longer time delays in response than is necessary.

  The TNM design calls for 5-minute deployments. Assuming that deployment instructions are also conducted via ICCP under the TNM design (an assumption made in the IIA's determination of cost impacts), the time delay for the Balancing Energy market response could be shortened considerably.[65] Note that this potential improvement is not a result of a nodal deployment per se, and theoretically could be accomplished under a zonal market structure by changing the protocols to reflect a 5-minute deployment and by transitioning to an ICCP notification mechanism. Since the Base Case market currently includes 15-minute deployment and XML communication, the positive impact of the TNM is noted here.

These three characteristics of the Base Case market design have a number of adverse impacts.

- First, with respect to portfolio bidding, actual system flows cannot be accurately predicted on the basis of scheduled information, so the system dispatch is less efficient. Some of this inefficiency (namely, the implementation of operational limits on Commercially Significant Constraints, or CSCs) was modeled in the EIA; but the EIA could not replicate the operators' efforts to estimate disaggregation, and it did not represent the ramping issues and the outcome of not providing capacity, such as Gas-Turbine capacity, to the Balancing Energy market. Also, the conservative ramp rates cause portfolios to be dispatched in a manner inconsistent with the dispatch that would occur under perfect information. Additionally, the portfolio impacts seem to result in undesirable Balancing Energy deployments and pricing outcomes. Further, these portfolio impacts flow forward into the Transmission Congestion Right (TCR) market, often resulting in under-funding the TCRs, which results in further uplift payments to cover the shortfalls.[66]

- Second, some participants believe that the current market design results in over-procurement and/or misallocation of ancillary services because of its ramping and scheduling provisions.[67] For example, the SOM Report states that, during hours when ramping is especially needed, ERCOT generally needs 25 percent more regulating capacity than it would need absent the portfolio scheduling.[68] Further, today ERCOT may deploy non-spinning reserves to increase unit commitments and the supply of Balancing Energy. This is an undesirable use of the operating reserve market (Potomac Economics 2004, p. 55). At a minimum, this operating policy adversely impacts the transparency of the Balancing Energy and Non-Spinning Reserve markets.

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[65] For example, with the Base Case, deployment decisions can be delayed by roughly 30 minutes, about 15 minutes for communication and price posting and a 15 minute deployment period. With the TNM, the deployment delay would shrink to close to 15 minutes (10 minutes for price posting and 5 minute deployment, assuming negligible communication time).

[66] See SOM Report, pp. 97–110.

[67] It is recognized that the underlying driver of the ramping issue—the fact that bilateral trades tend to contain peak blocks—is independent of market structure.

[68] Note that some market participants suggest comparing regulation quantities in ERCOT today with those in PJM following PJM's implementation of an LMP-based market as a measure of the potential benefit in the form of regulation savings. However, given that PJM is an interconnected region and ERCOT is essentially not, strict comparison of regulation quantities in ERCOT with those in PJM is inappropriate.

- Third, market design attributes that result in different actual and anticipated flows cause undesirable congestion pricing and TCR payment impacts.[69]

It should be noted that these adverse impacts are not the result of a *zonal* market design per se. For example, Potomac Economics advises that QSEs can use sub-portfolios even under the zonal market design (Potomac Economics 2004). In other words, under the current market rules portfolios can be disaggregated by the QSEs. However, that these impacts persist suggests the existence of some barriers—even if they are not market rule barriers—to resolution.[70] Nonetheless, the fact that the TNM design will necessarily require unit-specific scheduling and bidding and will make use of 5-minute deployments, and the fact that other drivers are directly given by the zonal market structure (e.g., lack of an integrated commitment process that fully recognizes locational needs), the movement to the TNM can be seen as having positive impact in this regard. In this same regard, however, while the TNM would support an integrated commitment, the TNM design did not call for it when this study was carried out.

On the other hand, it is unrealistic to expect that all operational problems can, or will, be eliminated by implementing a new market design. Just as the current operational problems were unforeseen results of the zonal market design, the TNM may create other unforeseen operational problems.

LMP-based markets also have operational problems. For example, a variety of factors can lead to price recalculations in a nodal market, such as software flaws, data entry errors, and communications failures. In the NY-ISO nodal market, for the first year, real-time prices had to be re-calculated for 3.6 percent of all 5-minute intervals.[71] Price recalculations cause market uncertainty and higher administrative costs—both to update prices and to address the implications of not being able to settle easily given the changing prices. Further, market participants' behavior in response to new market rules may be less predictable than the mechanical impacts of the rules themselves. In other words, the new market structure will tend to cause some initial confusion and will present a different set of incentives, both of which tend to cause generators to bid in new ways, to experiment with new bidding strategies, and to react to the new bidding strategies of other participants. Though such behavior may not be an attempt to exercise market power, it nonetheless causes some instability in pricing.

Thus, to say with certainty that a new market design will eliminate all operational issues would be an oversimplification of potential impacts. Rather it is trading the anticipated resolution of some operational issues—those that have, in fact, been shown to have some significant adverse impacts—for another set of potential operational issues of unknown severity.

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[69] The SPD-calculated flows can vary substantially, and often they are not close to the actual flows or limits for the CSC. Because transmission rights are generally sold based on the actual CSC transfer capability, this can result in substantial surplus congestion revenue or in congestion revenue shortfall that results in uplift charges. Under the current market design, it is very difficult to develop procedures for selling transmission rights that fully subscribe the available transmission capability (SOM Report, p. 131).

[70] It may also simply be the case that some market participants have large portfolios while some have small portfolios. Those with large portfolios probably value the operational flexibility that the portfolio scheduling and bidding provides, yet they may also find that some aspects of portfolio scheduling create inefficiencies.

[71] ISO-NE Six Month Report, pp. 33–34.

Changes that node-specific marginal pricing might cause

The fundamental change associated with node-specific marginal pricing is the movement away from Out-of-Merit-Order Energy and Capacity (OOME and OOMC) payments that simply recover from the market the actual cost under ERCOT's existing zonal market rules to pricing based on a single, optimized marginal-priced[72] outcome. Conceptually, under the TNM approach, consistent, nodal marginal price signals will be provided to those bidding in the Balancing Energy market (as well as to all loads on a load-zone basis), and these price signals will better reflect cost-causation principles. Movement away from OOM payments should[73] remove the incentives that currently exist to bid and/or schedule in such a way as to receive such payments.[74] Further, generators today have little incentive to mitigate intrazonal congestion, given that the congestion costs are uplifted. Node-specific pricing should provide the proper incentives to reduce the system cost of managing congestion[75] in both the short run and the long run.

The nodal market offers theoretical benefits besides the removal of the operational issues mentioned above. Many of these benefits are addressed as part of this Cost-Benefit Study's EIA. Others were addressed above (e.g. the operational limitations experienced in today's zonal market, and the potential exacerbation of intrazonal congestion that market participants may be able to create in scheduling practices).

Three types of impact should be considered, beyond the effects on efficiency and economically proper pricing signals:

- The complexity and transparency of a zonal model versus that of a nodal model
- The tendency for either model's solution (zonal or nodal) to be suboptimal
- The risks created by the implementation of either market design

The balance of this discussion assesses the extent to which complexity, transparency, and market design risks affect the benefits of centralized optimal nodal market design relative to zonal market design from a conceptual or theoretical perspective.

The major benefit of a zonal market design from a conceptual perspective is its commercial simplicity, namely that there are a small number of commercial pricing points and that the management of constraints other than the "commercially significant" ones takes place behind the scenes, with financial impacts small enough that market participants in general have little interest in the details of that management. On the other hand, the nodal model was meant to create a fully integrated and fully optimized system dispatch solution. Thus, in theory and by design, the zonal model is simpler and the nodal model is more complex. This zonal market simplicity is intended to support commercial/bilateral transactions, and—given the sharing of local congestion costs—it offers equal incentives to most[76] parties to work to relieve local congestion. The nodal model—by design—has very detailed methods that most market participants would not endeavor to fully replicate, but the economic efficiency merits of the nodal model are intended to justify its additional complexity.

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[72] "Marginally priced" refers to pricing at the marginal opportunity value and not necessarily the marginal cost.

[73] The SOM Report has several examples of empirical data supporting the notion that such incentives impact behavior.

[74] For example, a generation owner overscheduling resources in a nodal market in order to be curtailed down can cause the price at their generator node to be depressed as a result of the overscheduling, such that the profits for the generator are adversely impacted to the extent it does operate. In the zonal market, however, since the generation from a generator pocket does not see the depressed price it may create from the overscheduling unless it is marginal within the zone, there are fewer incentives to schedule and bid efficiently.

[75] Not the congestion costs per se, but rather the system costs.

[76] All but those who may be able to receive payments associated with the local congestion.

Similarly, the intent of zonal models generally is to distinguish the commercially (financially) significant pricing from the commercially insignificant operational considerations, thereby requiring limited algorithms for commercially significant market settlements and minimizing the risks of undesirable outcomes. The intention of the nodal market design, conversely, is to involve the commercial participants in the treatment of all system constraints (limiting factors), thereby ensuring an optimal outcome and minimizing the risk of improperly managing factors external to the market solution.

From a theoretical perspective, then, the two alternative market designs imply inherent trade-offs. However, two factors critically bear on the anticipated impacts of the possible movement from a zonal model to a nodal mode in ERCOT: (1) ERCOT's experience with the zonal model and (2) experience in other markets with the nodal model. To the extent that the existing ERCOT model is, in practice, neither simple nor transparent, and to the extent that intrazonal congestion is, and will continue to be, significant, then many of the theoretical benefits anticipated from a simple zonal market design are not being realized. Similarly, to the extent that, in practice, the complexity of nodal markets has proven manageable, robust, and workable in other U.S. nodal markets,[77] some of the potential risks and concerns about such a centralized system should be alleviated.

Actual experience in ERCOT suggests that the Base Case model is not simple.

- The commercial model is a networked flowgate model, and the pricing results of that model—especially as the number of zones increases—are not much less difficult to understand than the pricing results of the TNM. (In the TNM, loads are priced at the zonal weighted average price, which alleviates much of the need for loads to address the details of nodal prices.)
- Intrazonal congestion is significant ($100 to $150 million per year in 2002 and 2003).[78] Loads have therefore been required to address the operational management of constraints, making local congestion as important an issue for the Base Case as for the TNM. (In the TNM, loads will be settled zonally, so that the complexity of nodal pricing and the volatility of nodal prices most loads will see will likely be comparable to what they see in today's zonal market.)
- ERCOT's efforts to maintain a simplified zonal commercial model while managing significant intrazonal congestion using a full network model has resulted in a hybrid approach that is less than transparent.[79]

At the same time, participants in U.S. nodal-based markets seem to have few complaints about complexity or lack of transparency associated with nodal energy pricing. (See Footnote 77.) There are areas of concern regarding transparency in the Northeast markets, but these concerns not driven by nodal pricing per se. Instead they are primarily associated with the impact on nodal pricing of the Installed Capacity Markets and with system operator commitment and dispatch actions to manage reliability issues.[80]

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[77] Note that the scope of this effort did not include a series of interviews of various market participants. TCA's impressions in this regard are based on experience in the Northeast markets. In some cases all end user segments are actively involved in the market forums, and in another case there is very little participation by end users and small municipal segments. To the extent that certain segments have significant challenges operating in these markets given nodal pricing but have not participated significantly in the market forums, TCA is likely unaware of the impacts of these complexities on such participants.

[78] Potomac Economics 2004, p. 113.

[79] For example, given the operators' need to allocate portfolio schedules to individual units, the results of the zonal market are not knowable or always replicable.

This is not to say, however, that the *transition period*[81] associated with the implementation of a nodal market would not be without significant complexity and risk for market participants. All of them—but especially smaller participants—will need data in the transition period. In addition, participants will look for other market result that indicate operational and price stability (in the sense that the system operator no longer needs frequent recalculation of nodal prices, for example) if they are to feel that the market structure is manageable.

Another aspect of Change 1 that warrants consideration is the proposed reliance on the centralized dispatch algorithms that underlie both the SCED-based resource redeployment function and the nodal price calculator function that will produce the locational marginal prices imposed upon the QSEs. To the extent that these algorithms, models, and input data accurately capture all aspects of a participant's objective and preference function, these functions would be expected to result in a more efficient resource dispatch than the market participants would otherwise produce. But this model-directed dispatch theoretically could also be less efficient, to the extent that QSE-based scheduling and dispatch is based on a broad spectrum of real-world operating characteristics and resource constraints, rather than just the small subset that can be modeled within the SCED function.

Similarly, a potentially adverse impact of Change 1 is that its reliance on complex "black box" models to redeploy resources would reduce the transparency of system operation and of prices, decrease the ability of market participants to ascertain certain aspects of the legitimacy of resource redeployments, and increase customer difficulty in auditing settlement statements. However, given the Base Case market's current reliance on such models to resolve intrazonal congestion, the ERCOT deployment results are already subject to such models.

Given that an SCED is used today to redispatch the ERCOT system in real time for local congestion, market participants are already subject to some of the above risks. However, the consequences of adverse SCED outcomes under the TNM will be greater given the TNM redispatch for efficiency as opposed to the redispatch in the Base Case model of only units that have a significant network bearing on binding transmission constraints.

Node-specific penalties for uninstructed deviations

Under the Base Case protocols, penalties for uninstructed deviations are assessed on a portfolio basis; a QSE's uninstructed deviations are netted on a zonal or ERCOT-wide basis before penalties are calculated. The proposed design changes would assess uninstructed deviation penalties on a resource-by-resource basis. The proposed design changes for uninstructed deviation penalties would increase market participants' cost and complexity of doing business by requiring management of unit-specific deviations rather than portfolio deviations. However, given the nodal design, not managing uninstructed deviations on a node-specific basis would create the potential for significant gaming opportunities.[82] As a result, implementing the alternative (resource portfolio uninstructed energy penalties) would create larger adverse impacts than this expected increase in administrative burden. Thus while there may be an increase in the administrative burden of QSEs managing this impact, that burden is a result of employing a nodal design generally and is a price that must be paid in order to obtain the benefits of that design.

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[80] Specifically, that nodal pricing signals are impacted by energy from system operator actions that are not fully captured in the SCUC/SCED pricing results.

[81] "Transition period" is used within this OMIA to represent the time associated with preparing for the TNM and entering into the TNM through the time the it takes (if any) for the market algorithms to stabilize and the time it takes to generate historical nodal pricing data (one year or more).

Commercial Impacts

A. *Facilitation of Competitive Markets.* The efficient operation of competitive markets, and the willingness of potential new entrants to make the investments needed to enter such markets, both depend strongly on the "openness" of such markets. Transparency of market rules and market operation, and access to the information and tools needed to analyze the potential impacts of the market rules, are important to market participants' ability to hedge risk and to make day-to-day and longer-term business decisions.

   The design changes encompassed by Design Change 1 (nodal resource deployment) and Design Change 2 (nodal settlements) are closely linked. Based primarily on the extent of the current operational problems that would be alleviated under the TNM design,[83] and on market participants' acceptance of similar designs in other U.S. nodal markets,[84] it is expected that the TNM design will enhance the development of Competitive Markets in the long run and that it will create significant year-one benefits. However, given the potential creation of unknown new operational issues, this benefit is likely to be offset to at least some extent. Additionally, during the transition period, market participants will lack information about the nodal market outcomes, and it will be difficult for them to predict outcomes. This could tend to suppress market participation during the transition period. It is unclear whether these short-run adverse impacts will be greater or less than the potential operational and efficiency benefits—that is, whether the *net* short-run impacts on competitive markets are positive or negative. The impacts are expected to be positive after the transition period.

B. *Minimize Discriminatory Environment.* Beyond the transition period, real-time nodal dispatch is not expected to impact any particular class more than it does under the nodal market design. To the extent that it reduces the ability of some players to schedule in a way that maximizes their OOM payments, the TNM real-time nodal deployment may in a sense level the playing field, which could be considered to minimize the discriminatory environment.

C. *Efficiency of Production.* Given the potential for alleviating some of the significant operational limitations of today's zonal market, the TNM offers increased efficiency of production. This benefit would be tempered by any operational issues arising from the implementation of the new market design, especially during the transition period.[85]

D. *Efficient Resource Expansion and Efficient Grid Expansion.* Because the impacts of nodal deployment on efficient resource expansion and efficient grid expansion are much more driven by the pricing outcome of nodal settlements, these impacts are addressed in the discussion of Change 2.

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[82] This is expected to be the case especially if the TNM prices nodal energy on an ex-ante basis rather than an ex-post basis.

[83] Of course, unanticipated operational issues could develop under a new market design. However, the PJM, NY, and ISO-NE markets have not experienced irresolvable operational issues of any significance.

[84] See Footnote 77.

[85] See Footnote 81.

E. *Market Power.* The impacts of this set of design changes on the ability to exercise market power are uncertain. There have been long-running arguments as to whether or not a nodal pricing regime would decrease or increase the opportunities to exercise market power. Under the zonal market, more incentives may exist to exercise market power, because there are more situations in which costs are socialized rather than directly allocated to resources that may cause congestion. But even in the nodal market, to the extent that there are multiple markets within a zone due to congested local constraints and few resources capable of alleviating that congestion, the ability to exercise market power would continue to exist, probably comparably to the ability that exists today for OOME units. According to Potomac Economics, PJM Interconnection has limited the exercise of market power under its nodal market design by its strict adherence to local market power mitigation policies. (PJM 2004, p. 49) Market mitigation strategies were not assessed as part of this analysis to determine whether ERCOT TNM policies might be equally effective. See Change 2 for additional discussion of pricing policies and market power mitigation.

F. *Grid Reliability.* As discussed above, the expected resolution of operational issues will provide additional mechanisms for grid reliability,[86] although there are no reliability concerns in ERCOT today under the nodal market.

G. *Ability to Conduct Business*. The most prominent impact to this area should be the alleviation of ramping, deployment, and scheduling constraints that ERCOT now experiences with portfolio bidding and scheduling, and for which QSEs find there to be inefficiencies. Alleviation of these issues through the unit-specific representation is a positive impact. At the same time, however, QSEs that have large portfolios experience a reduction in flexibility in scheduling and operations. Other QSEs with smaller generator portfolios would benefit from the increased system efficiencies and should experience little or no loss in flexibility. Generally, participants in nodal markets seem to find participation straightforward. Loads' ability to schedule and settle on a zonal basis contributes to this. Aside from difficulties during the transition to the new market rules, the change is expected to be positive. (The transition would temper such benefits for a year or more.) It is expected that any increased impact of managing resource-specific deviation penalties would create a small negative impact relative to the benefits of the removal of operational (e.g., ramping) constraints. Finally, the likelihood of having to address new, unintended operational issues created by the TNM tempers the overall expected benefit.

H. *Administrative Costs.* The IIA addresses administrative costs. To the extent that the IIA does not capture all impacts, it is expected that the transition will create significant administrative burdens for both market participants and ERCOT. Following the implementation and learning period associated with a nodal market, ERCOT's existing (zonal-related) operational difficulties will have been alleviated, such that the net effect on any other (than the IIA) administrative costs may be lower or higher rather than necessarily higher.

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[86] ERCOT does not seem to have had reliability issues of significance due to the zonal market design. However, as the reserve margins decline, the existing operational issues would tend to be more problematic.

Change 2: Real-Time Market: Settlement on a Nodal Basis

Change 2 focuses on the *payment* changes associated with the implementation of the TNM. (The scheduling and dispatch of resources—which should to a large extent be driven by the node-based payment scheme—were discussed in connection with Change 1.)

With respect to payment changes, the significant drivers are the elimination of OOME and OOMC payments for resolution of congestion and the implementation of nodal payments for the cost of resolving all constraints, including local constraints.

Three noteworthy potential impacts are associated with these changes:

- Changes in social welfare through decreased system costs
- Cost or equity shifts among ERCOT market participants
- Changes in commercial risks

These impacts, and their relation to the OMIA Commercial Impacts, are discussed below. The discussions are not directly linked to these above bullets given their interrelatedness.

Although changes in social welfare and decreased costs are described here, the EIA captured and discussed the changes in social welfare created through the pricing and market-clearing changes and the impacts associated with price signals. Impacts on loads and generators were also discussed in the EIA. This Change 2 discussion therefore focuses primarily on other types of impacts.

Cost and Risk Shifts

The basic equity shift that would result from the move to the proposed nodal pricing structure is that entities that are insulated from the impacts of intra-zonal congestion under the zonal model would be required to pay congestion charges for the movement of energy from a congested area within a zone to an uncongested area within the zone. QSEs that use more than a pro-rata share of congested facilities might incur more costs; QSEs that use less than a pro-rata share could have lower costs.[87] Similarly, generators within a zone will be treated differentially under the TNM, possibly receiving higher prices if they are in a load pocket and lower prices if they are in a generation pocket. (In the Base Case the differentiating factor is the OOM settlements, and these tend to be payments to generators in both load and generation pockets.)

There are advantages and drawbacks to both conceptual models in terms of efficient use and expansion of the grid. The purpose of this discussion is to identify the impacts of moving from a market structured to socialize local congestion costs to a market in which those costs are directly assigned. These impacts may affect individual incentives for resource expansion and tend to affect certain users in opposite ways to other users—that is, creating winners and losers.[88]

Given the TNM's direct assignment of congestion costs and system-wide allocation of excess congestion rents (load payments to ERCOT, and ERCOT payments to generators); with Change 2 there is a cost shift to users who disproportionately use local paths and to those who use especially congested paths. Again, this general effect was evaluated as part of the EIA (although impacts to specific users were not assessed).

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[87] Note that this is not strictly true: The prices of the particular intrazonal constraints in the TNM case, and the relative costs of all other constraints in the zonal case, also have an impact.

[88] Where "winners and losers" is simply a shorthand way of saying that some parties will bear a higher financial or risk burden and others will bear a lower financial or risk burden as a result of the change.

In addition to the cost shifts, there are shifts in the ability to hedge. Under the zonal model there are no ERCOT instruments available to QSEs for hedging local congestion costs. In this sense the TNM is an improvement, because hedging instruments are possible under a nodal market. To the extent that uplifts are either insignificant or predictable, the need for, and the value of, a hedging instrument in the zonal market is low. On the other hand, QSEs under the TNM can be subjected to higher (or lower) congestion costs and to prices that are probably more volatile because of the loss of the geographic smoothing of the zonal model uplift allocations. Thus, while hedging ability is higher, the need to hedge is likely higher, and hedging will require business processes and business costs.

Thus, while there has been a general acceptance of the efficiencies of LMP-based markets by participants in such markets,[89] cost and risk shifting continue to be highly debated. Much of the debate in LMP-based markets revolves around the definition of load areas and the settlement of bilateral contracts. In a sense, a movement from socialization to direct assignment can shift the focus of certain issues (such as upgrades to resolve congestion) to a debate between those who will benefit from and those who will be adversely impacted by the system change. And with such outcomes there is the possibility for a shift focus from resolution of general system or market issues (such as the local congestion issues) to maximizing a participant's own value.

Experience in other markets[90] suggests that issues such as cost and risk shifts will probably remain "sticky" in ERCOT under the TNM. For example, the management of OOME and OOMC cost associated with the Dallas–Fort Worth (DFW) area has been part of the dialog associated with zonal model operations. Many of the operational issues associated with congestion management could have been alleviated through the creation of a DFW congestion zone.[91] The creation of such a zone today, however, would present several challenges, including the treatment of bilateral contracts and the equity issues associated with such a change. Moving to the TNM will leave many of these issues open. If DFW loads continue to be combined with the rest of the North zone, there will be load cross-subsidies. Furthermore, QSEs will be subject to a number of congestion risk issues. For example, a load holding a contract for a seller's choice of delivery in the Northern zone may find itself at risk for a significant amount of congestion between the seller's desired delivery point (likely a low-priced node) and the (higher) load average price. In short, although there are merits to the pricing signals and economic incentives, as noted herein, there are risk and cost shifts for which assessment and mitigation will have a cost, at least for some market participants.

Risk Management Impacts

The proposed design changes may also create new risk management issues. Under the current system, payment for most of the energy that flows within the ERCOT grid is handled through bilateral agreements between QSEs, and ERCOT is at risk (of nonpayment by a defaulting QSE) primarily for balancing energy. With ERCOT's relaxation of the balanced schedule requirement, and to the extent that market participants use this feature to buy or sell energy, the users of the Base Case zonal markets have begun to assume more counter-party risk, however the limited participation in the Imbalance Energy market may be.[92]

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[89] See Footnote 77.

[90] Based on TCA's experience in other U.S. ISO/RTO markets.

[91] It is not the intent here to advocate for any particular treatment of zonal boundaries, but rather to point out the parallel issues that may continue to exist under a nodal market. In fact, the issue and approach with respect to DFW was discussed throughout the SOM Report (see, for example, p. 100).

Under the TNM, especially with the anticipation of the EHDAM, it is expected that the volume of transactions through the centralized TNM will be significantly higher than in the Base Case balancing energy markets. The anticipated liquidity and depth of the TNM markets is a positive impact. However, a secondary effect is as follows. To the extent that the TNM provides incentives for additional bidding into the balancing energy market, and that it ultimately provides incentives for additional participation in the day-ahead market with EHDAM, a greater volume of energy tends to create larger counter-party risk, and this suggests that ERCOT's credit standards may have to be especially robust. With respect to the market design itself, assuming that a QSE's settlement with ERCOT is based on net settlements,[93] the movement to an injection and withdrawal structure for a QSE's own bilateral transactions with the TNM should not create any additional credit risk.

Algorithm/Process Risks

Locational marginal pricing is, in theory, consistent with the economic principle that prices in a competitive market should reflect short-term marginal cost. However, the actual implementation of LMP rests upon a large number of assumptions, many of which are not firm or proven. The calculated LMPs will be sensitive not only to the veracity of the model but also to the model's data inputs, which include transmission element limits and the manner in which nomograms and other complex network constraints are modeled, for example. Thus, the inherent uncertainty that underlies transmission line limits (often based on assumptions concerning ambient temperature or wind speed), or whether or not dynamic line ratings are used for a particular element, suggests the existence of some algorithm and/or process risks for individual QSEs.

It might be possible to mitigate some of these risks by extensive testing of the model and of the sensitivity of its outputs to the input data. For example, making the LMP engine and/or database available to market participants for validation, prediction, and settlement could enable such testing and would also mitigate any transparency concerns and algorithm/process risks associated with the nodal approach.[94]

Although an SCED method is in place today for the dispatch associated with local congestion, its application is limited to redispatch of units that have a significant impact on binding constraints only. The incremental risks of the TNM SCED include the expansion of the application of the SCED to include deployment beyond simple congestion management and to the expanded application of such models to produce nodal prices.[95]

Additionally, the OOME-based congestion management system that would be replaced with LMP also conveys significant process risk (it is not fully transparent, given ERCOT's need to disaggregate portfolios in a manner that is not an absolute science, it is not reproducible, it is complex, and it is subject to ad hoc workarounds; and because of all these factors it is subject to disputes).

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[92] This is assumed based on the fact that more trades within the market would tend to create more volume and more trading partners.

[93] No protocol language to this effect was identified by the CBCG. To the extent that a QSE's injections may be at risk (rather than simply net settlements) should another QSE default, then the credit risk for a QSE would tend to increase with the TNM.

[94] However, SCED engines are complex and are not easily examined or auditable by market participants.

[95] That prices to most load will be at the load area price dampens the impact of any individual nodal price.

It has been our experience that although the *algorithms* associated with the LMP engines may be less transparent to many market participants than zonal model algorithms, the *outcomes* of those engines are more transparent. In other words, while some participants may find it difficult to understand or reproduce all of the detailed calculations that are performed in the LMP engine "black box," those participants find the resulting pricing information to be clear, useable, and a valuable input to pricing analyses. It is likely that the TNM market would be viewed as less transparent than the Base Case during the transition period,[96] when market participants may feel themselves at the mercy of the "black box" and as yet have no resulting pricing history. In the long run, especially given a stable operating history, market participants will generally depend more on the TNM outputs and less on the algorithms and will find the market more transparent than the Base Case.

Long-run Price Signals

Two of the important Commercial Impacts that the OMIA seeks to address are the extent to which the proposed design changes promote (1) efficient grid expansion and (2) resource development.

With respect to grid expansion, long-term transmission investments must be justified primarily on the basis of anticipated future demand and long-term projections of future costs, rather than on historical uses and congestion costs. An exception to this rule is created by ERCOT's goal of removing high local congestion through short-term management followed by mid- or long-term transmission upgrades. The ERCOT planning staff uses OOM payments under the Base Case as a basis for identifying the need for such actions, and it is expected that they will similarly use nodal prices as a basis for such reviews under the TNM. Thus implementation of TNM is not expected to have any impact on transmission expansion. Expansion is a function of ERCOT actions,[97] and ERCOT already employs nodal tools to forecast transmission needs. Thus, nodal pricing provides no direct advantage or disadvantage in the area of grid expansion. However, as stated under Change 1, with nodal pricing there is the possibility for a shift of focus from resolution of general system or market issues (such as the local congestion) to maximizing a participant's own value. This change in focus could adversely impact the resolution of transmission issues for the greater good of the system.

The linkage between LMP-based congestion pricing and efficient resource development is stronger than the linkage with transmission expansion. In the short run, LMP would provide price signals that should stimulate the siting of resources where they are needed. This should be an improvement over the current zonal model, in which there are clear price signals regarding siting choices between zones, but limited economic penalties for choosing to locate at congested locations within a zone.

The overall LMP structure, including that proposed in the TNM, does leave open the risk that the value of a proposed resource at a location that is desirable on the basis of current LMP signals could be substantially diminished by changes (such as transmission reconfiguration or ratings changes, load growth, or other new resources) that create or alleviate future congestion. However, this risk exists in both the proposed nodal model and the current zonal model for the zonal siting value of a generator. Additionally, resource investment under nodal markets creates incentives for developers to strategically consider the size of the resource being added. A generator who sites in a load pocket and thereby fully provides for the load may cause the LMP to go down. Instead, generators are incented to develop just a bit less than the capacity needed to entirely resolve the transmission constraints.

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[96] See Footnote 81.

[97] Note that the issue of economic independent transmission expansion has not been resolved by LMP-based market designs, other than in the case of D.C. transmission siting perhaps (where usage can be controlled). Given the pricing policy, the addition of new transmission causes the difference in nodal prices to diminish and by nature of the addition, causes the value to go away.

Potomac Economics has concluded, on the basis of empirical data, that an LMP-based market induces more siting and proper siting.[98] In the last several years, however, several factors are driving siting in such a way that it may not be appropriate to use the empirical data and strictly conclude a cause and effect connection between nodal pricing and siting.[99] First, in the early 2000s there were an overabundance of development announcements, and a combined level of planned development that well exceeded the needs of the system. Many plants were developed and others were cancelled. In ISO-NE, there had been reliability payments for generation in load pockets. Given the timing of the addition of the resources in ISO-NE, so closely coupled with transition to nodal pricing, such generation must have been planned to some extent prior to nodal pricing being effective. It is not possible to determine whether the anticipation of nodal pricing caused generation to get built in the "right places" or whether the generation would have been developed in those places absent nodal pricing.

Further, load pockets continue to exist in the Northeast markets. TCA believes that there are two countervailing forces that are preventing nodal pricing from entirely "solving" siting issues. First, there are strong exogenous issues, including "not in my back yard" (NIMBY), that continue to overwhelm nodal pricing signals. (Consider Long Island and southwest Connecticut, for example, where barriers to siting are such that nodal pricing signals are no more effective than zonal pricing signals.) Second, with respect to siting, existing market structure issues continue to influence the effectiveness of the pricing signals. In a sense these markets yet are not fully "mature," given the persistence of such issues, which include the region-wide vs. locational installed capacity policy in PJM, the coupling of system operator treatment for reliability and the resulting impact to dampen market energy prices (as a result of commitment or dispatch of energy outside of the LMP market mechanism, for example), and the refinement of market mitigation procedures. TCA's experience is that participants in the Northeast markets generally believe that such market structures lead to uncertainty, as well as dampen the prices that would be needed to support development of new generation in the most critical constrained areas. Such market characteristics are being addressed, and it is anticipated that a complete set of the right incentives will eventually allow nodal energy pricing to have a significantly stronger influence. However, the fact that PJM is still in the midst of such market structure refinements suggests that it is not a fast route to such market maturity.

In short, TCA believes there has been insufficient time since the inception of nodal pricing in ISO-NE to strongly demonstrate a cause-and-effect connection between nodal pricing and siting outcomes, and that the longer operating history in PJM suggests that there are still factors that dampen the effectiveness of the theoretical potential of the nodal pricing signals in that market.

In the case of smaller resources with either smaller capital investment requirements or shorter payback horizons (such as distributed generation and demand-side management), the linkage between LMP-based congestion pricing and efficient resource expansion is theoretically stronger than for large resource development, because there is less likelihood that grid operator or third-party actions would change the value of the location during the investment payback period. For such resources, the proposed TNM provides incentives that are far more site-specific than those provided by the current zonal model. However, many of the issues associated with siting generally would also affect small generators and increased participation on the demand side.

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[98] For example, in PJM (PJM SOM Report 2003) 5000 MW of capacity was added between October 2002 and October 2003 (p. 39), and over 15,000 MW is in the queue for future development (p. 70). In ISO-NE, the typically congested area of NEMA/Boston has experienced reductions in congestion since the inception of the LMP market, due in part to the development of generation in this area (NE ISO SOM Report, p. 26; NE State of Markets Report, p. 8).

[99] Note that this discussion regarding the demonstration of the effectiveness (or lack thereof) of nodal pricing to cause responsive siting results is based on TCA's general understanding of the subject through participation in the Northeast market rather than as a result of any thorough quantitative analysis.

Aggregation of nodal prices in load zones and Non-Opt In Entity zones

The concept of bifurcated pricing for loads and resources (paying resources nodal prices and charging loads the weighted average of the nodal prices in a zone) is, strictly speaking, contrary to the economic principles that underlie the nodal pricing system. However, such pricing policies have been shown to be workable[100] and, in a sense, to provide a necessary element of risk hedging in other markets.

That loads acting as resources be eligible to receive the nodal price, as the TNM proposes, is seen as a critical element to encourage the development of demand-side resources. However, depending on implementation details, this approach might also create gaming incentives if the resource portion of a facility that comprises both load and resource (for example, a co-generator with a local load) can freely opt to receive the nodal price or the zonal price (for example, by choosing when to net its output against the local load). In such a case, the resource could opt back and forth between the higher of the zonal or nodal price. The end result would be that the other loads in the load zone would be subsidizing the load/resource that is capable of playing the game. At low levels of penetration, this probably does not create a significant adverse impact, but there would be an adverse impact at higher levels of penetration.

Commercial Impacts

A. *Facilitation of Competitive Markets.* The long-run impacts are expected to produce improved transparency and improved price signals, and experience in other markets[101] suggests that these are the predominant impacts. The volatility of experienced prices is expected to increase under the nodal pricing structure—primarily impacting generators and Loads acting as Resources (LaaRs), and to a lesser extent the balance of the loads paying load-weighted average prices. Complexity produces adverse impacts during the transition period—especially for smaller market participants—and such impacts are expected to be alleviated with operating stability and history.

B. *Minimize Discriminatory Environment.* The movement from OOM pricing to explicit nodal pricing increases transparency, which improves competitive markets generally. Cost and equity shifts will create adverse impacts for some participants. The process and algorithm complexities are also expected to create adverse impacts during the transition period, especially for small market participants. However, the expected long-run benefits may—on an ERCOT-wide basis—create relatively more benefits. However, with respect to "discrimination," the OMIA factors indicate that smaller participants will be disproportionately disadvantaged by the adverse impacts, if for no other reason than that the sophistication needed does not scale down linearly with participant size. Ultimately, although it is not possible to determine the relative strengths of these factors with certainty, beyond the transition period the market-wide drivers produce positive competitive impacts, despite the cost and risk shifts. Whereas the transition period with respect to mastering the institutional knowledge and infrastructure seems to be roughly a year or two, TCA's sense is that it may take significantly longer than this to realize nodal market benefits in areas such as investment price signals, at which time smaller players might reach the benefit-cost crossover point.

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[100] Based on the consultant's experience working with market participants in PJM and the NY ISO.

[101] One measure, for example, is the volume of trading (liquidity) in various markets. Analysis of the Intercontinental Exchange trading volumes for ERCOT, PJM, and ISO-NE suggests that volumes in this third-party exchange were 3.5 to 5.5 times higher in PJM and ISO-NE than in ERCOT when adjusted for overall market size.

C. *Efficiency of Production.* The production efficiency impacts of the TNM are presented in the EIA. The potential OMIA impacts related to these EIA impacts concern the risk that the TNM algorithms will fail to produce the expected benefits. To the extent that the processes and algorithms employed by ERCOT to create nodal prices do not completely or accurately represent the efficient decision parameters, increased reliance on a centralized dispatch model would have adverse effects. Two primary facts suggest that these offsetting drivers are not significant: (1) that ERCOT currently employs a SCED to dispatch units for local constraints in real time and (2) that no aspect of the TNM will force market participants to participate in the centralized dispatch, meaning that QSEs could make bilateral and self-scheduling decisions when they believed their own decision parameters were better than ERCOT's.

D. *Resource Expansion*. Impacts of improved pricing signals for resource siting given nodal price signals are part of the EIA.[102] However, TCA's further study of how the markets are responding to the price signals have shown some continued institutional barriers to the marketplace seeing the price signals. As discussed in the Change 2 discussions above, these include exogenous factors (e.g., NIMBY) that continue to have strong influences, and the fact that other market structures may be dampening the price signals that are needed to overcome other factors. While price signals are viewed as beneficial from the start of nodal market operations, their full benefit may take time while other market structures are refined.

E. *Grid Expansion.* As discussed above under "Long-Run Price Signals," the nodal price signals will continue to support ERCOT's existing short-run use of congestion pricing but will not significantly enhance that ability. That market participants under nodal will have a stake in whether congestion exists or is alleviated is seen as an impediment to grid expansion to resolve transmission issues. It is not possible to tell how strong this impediment is other than to note TCA's experience that this effect seems to be at play in policy debates in Northeast markets.

F. *Market Power.* While the design changes will have impacts on the opportunities to exercise market power, it is difficult to draw any conclusions as to whether the net impact would be a noticeable improvement. There have been long-running arguments as to whether a nodal pricing regime would decrease or increase the opportunities to exercise market power. Under the zonal market, more incentives may exist to exercise market power, because there are more situations in which costs are socialized rather than directly allocated to resources that may cause congestion. Some of these incentives (e.g., the incentive to over schedule at congested intra-zonal locations) would be removed by the design changes. (See Change 1, Commercial Impact paragraph E, for a related discussion.) Additionally, Potomac Economics suggests that there is a delicate balance between local market power mitigation and the assurance that appropriate economic signals are available for investment (PJM 2004, p. 18). As a result a TNM mitigation design that provides for a high-level of confidence with respect to the exercise of market power may suggest a lower level of assurance with respect to signals for generation expansion. Given that similar dynamic trade-offs exist with respect to managing the exercise of market power under the current market design, however, it is unclear how nodal pricing will impact the exercise of market power.

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[102] Improved siting is one of the elements of the EIA that contributes to impacts quantified in the EIA for the Nodal Change case. However, the EIA did not isolate this benefit. As a result, the benefits of the improved siting alone are not given by the EIA.

G. *Grid Reliability.* To the extent that Change 2 promotes more efficient resource siting, benefits related to improved reserve margin[103] would be expected in addition to those deployment benefits noted in Change 1.

H. *Ability to Conduct Business and Administrative Burdens.* These Commercial Impacts are grouped because in the sense of nodal pricing both impacts are affected by similar drivers.

The costs to participate in the TNM are captured in the IIA. It is expected that market participants will have more difficulty maneuvering through the TNM, given the complexities of the algorithms (the LMP algorithms and those of the Congestion Revenue Rights, or CRRs, used to hedge the LMPs) and (perhaps) the individual treatment of portfolio units. The impact is expected to be strongest during the transition period. Thereafter, the availability of published nodal prices based on codified methods (rather than on workarounds) may be more significant than the administrative burden of the new markets. And as discussed under B above and later in the segmentation section, small players (Municipalities, small Retail Energy Producers (REPs), and individual participating loads are expected experience disproportionately adverse impacts.

The potential exists for the burdens associated with conducting business for ERCOT to be lower with the nodal market, but not for the added support required of ERCOT to address market participants' concerns. This would be the case if the alleviation of the operational and incentive concerns provided more benefit than the added overhead of the more involved nodal market bidding and settlements. However, it would require considerable speculation to characterize (with respect to direction and/or relative magnitude) specific impacts for ERCOT beyond the transition costs captured in the IIA, so such characterization is not attempted here.

Change 3: Congestion Revenue Rights

This design change proposes the creation of point-to-point Obligation CRRs and point-to-point Option CRRs of durations of up to two years. (Flowgate CRRs were not considered in the OMIA, because it is not clear when, if ever, they might be made available.). CRRs will be made available between combinations of resource nodes, load zones, and trading hubs, subject to a simultaneous feasibility test (SFT).

The purpose of CRRs is to enable market participants to hedge the financial risks created by the unpredictability of nodal prices. CRRs provide only a limited hedging ability, as is the case for the existing TCR instruments. For example, the two-year (CRR) and one-year (TCR) maximum durations of these rights are too short to provide substantial risk protection to developers of large capital resources. But because the purpose of the OMIA is to compare the proposed design change to the existing system, this discussion focuses only on identifying the differences between the two types of rights, and then only on those differences that might have significant Commercial Impacts.

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[103] For example, capacity that is added under the Base Case but that cannot be delivered given local constraints would not be as effective at meeting reserve margin objectives as capacity that it is sited where its output could be delivered to where it is needed.

Underlying Market Behavior and Rights Outcomes

Primarily because of portfolio bidding, the current Base Case market design causes a lack of conversion of auction prices and congestion payments, which results in under-funding TCRs.[104] This causes distortions in the form of revenue shortfalls that are uplifted to loads. For this and other reasons, the TNM's CRR market is expected to function more transparently and more consistently with cost-causation principles. However, since this is more an outcome on the rights market of the deployment processes than a result driven by the rights market design itself, this issue is included in the impacts associated with Change 1.

Maximum Duration of Congestion Revenue Rights

Whereas the maximum duration of TCRs is one year, CRRs would be offered with a two-year duration. This is a positive development proposed in the TNM design (though not linked to a nodal versus zonal market design), which will enable QSEs and others to hedge the transportation-related risk of mid-term energy purchases.

Complexity of QSE Operations/Risk Shift

Additional Burdens of the TNM
The TNM is likely to increase risk or complexity for QSEs. For example, if a QSE's objective is to be fully hedged with certainty, obtaining that full hedge will be more complex. Alternatively, if a QSE is not interested in managing the level of complexity, it is likely that the QSE will be obliged to take on more risk.

Consider the situation of a QSE that is responsible for a portfolio of three 100-MW resources located at three different nodes, and a demand of 180 MW located at a fourth node. The QSE will typically schedule those resources differently from day to day, depending on unit availability, costs, congestion, etc. The QSE desires a complete hedge against ERCOT's congestion charges (the differences in the LMPs).

Under the existing zonal pricing regime, if the QSE's resources and loads were in the same zone, no TCRs would be required. Under the nodal pricing regime, the QSE would need to acquire, for each of the three different resource nodes, 100 MW of CRRs from the resource node to the load zone[105] in order to acquire, with certainty, a complete hedge against congestion costs while retaining full scheduling flexibility.[106] (And aside from the additional complexity and costs, it is possible that the SFT would prevent that many CRRs from even being made available, because the system might not be able to handle the 100-MW outputs of all three resources simultaneously.) Thus, for this QSE, the CRR regime would be considerably more complex than in the zonal model.

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[104] SOM Report 2003, pp. 97–110. Page 98 states: "It is likely that real-time physical flows were actually positive during this period diverging substantially from the SPD-calculated flows." Page 100 further characterizes the differences between SPD-calculated flows and the actual flows. On page 101, it is observed that "because SPD-calculated flows can be substantially different than actual flows, the ERCOT operators manage congestion by lowering the SPD limit when a constraint is physically binding to prevent additional flow over the CSC." Page 104 further documents that: "Because transmission rights are generally sold based on the actual CSC transfer capability, this can result in substantial surplus congestion revenue or congestion revenue shortfall that results in uplift charges."

[105] Alternatively, the QSE might try to acquire, for each of the resource nodes, 100 MW of CRRs from the resource node to a hub, plus 180 MW of CRRs from the hub to the load zone. There are numerous other possibilities.

Balancing Factors
In contrast with the above example, if the QSE's three portfolio resources were each located at nodes in different zones, with the demand located in a fourth zone, the QSE's TCR requirements under the existing zonal model might not be considerably different than under the CRR regime. Thus, the move to the CRR regime would likely create new burdens for QSEs that try to hedge the exposure associated with nodal pricing, but the magnitude of those burdens would differ from QSE to QSE. For example, parties that conduct business across multiple zones today would likely be accustomed to matters that would seem disproportionately complex to a more localized market participant.

Further, given that the ERCOT zonal model already includes multiple (networked) zones, and especially to the extent that the number of zones in ERCOT would increase, participation in ERCOT's TCR process is itself not a simple process.[107]

Additionally, the QSE in the first example does not (and cannot), in the current Base Case zonal market, obtain a full hedge because there is no ERCOT instrument to hedge the cost of the intrazonal congestion (though this is not a significant outcome if the uplifted local congestion management cost is small and predictable). Although the cost of local congestion is probably less volatile in the zonal market, given the geographic smoothing, in the first example there is not a full apples-to-apples comparison between the two market designs.

Liquidity of CRRs

The difficulty of hedging against nodal congestion costs while operating a flexible resource portfolio would be lessened if a robust marketplace developed for the trading of CRRs. This requires liquidity: a marketplace with a sufficient number of buyers and sellers, and with a sufficient quantity of the CRRs desired by those buyers and sellers.

Compared to a marketplace in which a limited number of products (TCRs for Commercially Significant Constraints under the zonal model) might be traded, the liquidity of a marketplace for node-to-zone CRRs or node-to-hub CRRs (that is, CRRs from generator—or LaaR—points to major trading points) would probably be very limited. This is simply because there are fewer buyers and sellers for those specific products than there are for major paths such as TCRs. Few buyers or sellers would require the node-specific products that might be offered. Instead, in order to have a liquid market for rights to or from specific nodes, there would have to be speculative trading (buying and selling of rights to arbitrage the difference between auction prices and expected congestion revenues) by additional parties in order for there to be a liquid, efficient market.[108] (Absent speculative trading, parties that need rights may not be able to find sellers, and parties who have excess rights may not be able to find buyers; price discovery would be minimal, and auction prices versus congestion CRR payments would tend to have less convergence.) A hub-to-hub or hub-to-zone CRR marketplace would be more liquid.

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[106] Note that less than all of the noted CRRs might provide a *full* hedge, given that the unused rights would still collect congestion revenues. However, it would be impossible for a QSE to know which set of CRRs, other than ones covering the QSE's possible schedules, would be required to obtain the full hedge with *certainty*.

[107] Historically in the TCR auctions, participation has been relatively limited (to roughly 13% of all QSEs). This *could* suggest barriers to participation. However, it could also simply reflect the fact that many participants in a zonal market either have their activities primarily limited to one zone or do not find the need to hedge transactions across zones. A third possible explanation for the limited participation is that (at least in the initial TCR auctions) TCRs were overpriced (sold for more than the actual congestion rent payments returned but significantly more than simply what a risk-premium value would suggest), so that prudent buyers did not participate in the markets given other buyers' bidding strategies.

However, to the extent that there is no viable TCR secondary market today, the ability for a QSE to sell the CRR's transmission capacity, and potentially to a wider market given the nature of the SFT, in subsequent (monthly, for example) auctions would provide an improved mechanism for the creation of liquidity. In other words, a participant that owns a right for which there is no particular buyer for that specific CRR can offer the right back into the auction, and any other user who could gain from that CRR's underlying network capacity could obtain that capacity as a result of the seller selling the original right, even though the new buyer has different injection and/or withdrawal points. This allows a trade to occur where one could not have otherwise been, thus creating social value.

Coverage in the Event of Contingencies

In the current model, TCRs retain their full value despite changes in network capabilities. In the CRR proposal, CRRs would be derated (although derated CRRs would be repurchased at one of the CRR market clearing prices). Although this does not necessarily represent a loss in value (as the purchase price is adjusted), it does constitute another risk shift (exchange in purchase price value, for a loss of coverage of the congestion cost) from the providers of transmission service[109] to the QSEs that use transmission service. In other words, when there is a deration there is a shift in risk from ERCOT-wide loads to specific CRR holders.

Similarly, under the zonal/TCR model, the costs stemming from low-probability, high-impact contingencies related to system elements within the zones are socialized through intra-zonal congestion costs. Under the nodal/CRR model, the impacts of such contingencies (and even the impacts of operational changes that cause the network's capabilities to differ from those of the nominal network used in the SFT) are shifted from ERCOT-wide loads to specific individual market participants (the users of the constrained interfaces). Therefore, and as indicated in Change 2 with respect to volatility and above in the general examples regarding TCRs and CRRs, the need for a hedging instrument is greater under the TNM.

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[108] Take, for example, the case that there is only one generator located at a node. There would be very little volume of trades of that generator's CRRs absent the participation in the CRR market of parties simply interested in speculative trading, because there would only be the one generator (and potentially the LSE or LSEs it serves) interested in those rights.

[109] In this context, the "providers of transmission service" are really the grid-wide loads that pay for the capital and operating costs of the grid. ERCOT and TDSPs are essentially just pass-through entities for the purposes of congestion and TCR/CRR costs and revenues. Under the TCR model, the loads throughout ERCOT (the same loads that pay the capital and operating costs of the grid) essentially underwrite a TCR insurance pool, standing behind the full value of the TCRs in return for higher premiums paid by TCR purchasers. (The clearing prices for these non-deratable TCRs would be expected to be higher than those for TCRs that did not include such a feature.)

Creditworthiness Concerns

The proposed creation of Obligation CRRs raises the issue of how to develop creditworthiness tests to ensure that the CRR purchaser will make good on its obligation to pay ERCOT. This is particularly so in the event of a high run-up of prices at particular nodes, or if congestion unexpectedly reverses direction. If this risk issue is not properly addressed, some market participants[110] will be allocated the impacts of any defaults by holders of Obligation CRRs. Given only preliminary details regarding ERCOT's protection against these risks, we can say that there may be the adverse impact of the need for increased credit management or an additional burden on ERCOT to ensure that credit risk is kept to a comparably low level.

The issues noted above indicate that five aspects of the CRR proposal are most likely to have Commercial Impacts on the market participants, when compared with the current TCR regime:

- The maximum duration of CRRs would be doubled to two years[111]—an improvement, although still probably too short to meet the needs of resource developers and parties to long-term power purchase agreements.
- The proposed CRR product would be a more limited risk-hedging instrument than TCRs because of the proposal's limitations on coverage in the event of deratings and system disturbances. The nodal market design itself may also make CRRs more limited risk hedging instruments than TCRs, because of the increased likelihood that facility deratings will affect CRRs (given that CRRs would exist for many more elements than in the zonal model) and because of the complexities associated with a QSE's ensuring that the proper CRRs are acquired to provide a full hedge.
- The complexities of participating in CRR auctions and of trying to use CRRs to hedge against nodal prices will generally be greater for most market participants.
- Guaranteeing a full hedge with CRRs, relative to TCRs, will be more challenging (and thus a disadvantage over the burden/price risk spectrum). Though having a guarantee of a full hedge might not be an objective per se, it is seen as an adverse impact of the CRR product relative to the TCR product.
- The liquidity of CRRs and the prospects for a strong secondary market in CRRs for node-to-hub/zone CRRs would likely be low. However, there is no indication that a strong secondary market for TCRs exists in ERCOT markets today, so the incremental impact is likely small.

The potential impacts of the CRR proposal also include (1) risk-shifting from the transmission service provider (in essence, the loads, ERCOT-wide) to specific grid users (QSE, generators, marketers, or loads) given the impact on CRRs of the local constraints and the change in duration policies; and (2) increased costs of doing business arising from a greater complexity of determining how to bid for rights, greater complexity in managing rights, and more uncertainty in dealing with uncoverable node-to-hub congestion price risk. As noted earlier, extra complexity is generally more of a burden on smaller market participants.

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[110] The market participants may be limited to other CRR holders to the extent that the credit and default mechanisms are established such that payout of revenues to CRR holders is dependent upon the inflow of revenues from other CRR holders. Alternative clearing mechanisms that could be envisioned would shift the risk to QSEs generally.

[111] This is a feature of the TNM design that is not linked to a zonal or nodal market structure to the extent that zones are not redefined more than every two years.

The CRR proposal is nonetheless practical, and many (but not all) of the limitations outlined above are an unavoidable consequence of the decision to migrate from a zonal to a nodal model and thereby directly apply cost-causation principles to the allocation of congestion costs.[112]

It is therefore important to maintain a broad perspective: if the nodal model overall achieves other, more substantial goals, or if it solves important problems that the zonal model cannot address, then the CRR drawbacks are probably secondary by comparison. Once again, experience in markets that have implemented nodal pricing indicates that, whether or not it is the best system to use, it is a system that can be made workable. That experience also suggests, however, that while substantial liquidity can evolve for hub- and zone-based rights, the liquidity of financial transmission rights to individual nodes is still not evident. Further, analysis of the convergence of prices of LMP-based transmission rights indicates that pricing in the rights auctions continues to be inefficient.[113]

Commercial Impacts

A. *Facilitate Development of Competitive Markets.* Change 2 presented the other relative benefits associated with nodal pricing generally. Participants' hedging nodal prices is seen as more complex, given the challenges of procuring node-specific CRRs (for injections) and obligation-type CRRs, and given the challenges of effectively forecasting congestion risk and of understanding the algorithms so as to participate effectively in the market. The potential for more liquid secondary trading, given the ability to sell CRRs in subsequent auctions, is a positive impact. The relative strength of these countervailing impacts is unclear.

B. *Discriminatory Environment.* Notwithstanding other impacts discussed elsewhere in this report, because the complexities and costs outlined above are not proportional to the size of the QSE,[114] the proposed CRR design features would tend to adversely impact smaller QSEs disproportionately.[115]

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[112] The reference here to cost-causation is the traditional one in which a user's marginal impact on system cost is reflected in that user's nodal price. It does not speak to the extent that that user had a long-run causation in the build out of the transmission, such that certain congestion costs accrue in the first place.

[113] For example, TCA's analysis of the NY ISO Transmission Congestion Contract (TCC) market suggests that the TCC clearing prices are still only half of their expected value, even after making allowances for risk aversion, suggesting that market participants may continue to find it difficult to develop accurate expectations of NY ISO market prices. (See TCA NY TCC Analysis summary at <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=76&b=>.)

[114] For example, the core cost of producing a price forecast is approximately the same whether the forecast is needed for a small QSE or for a large QSE.

[115] There are many factors affecting this relative disadvantage. It is expected to be greatest during the transition period, when there is no historical data available to allow QSEs to forecast congestion costs. Even with operating history, however, any significant topological change or resource change will impact the future LMPs. Conversely, however, small QSEs are subject today to somewhat similar impacts in the TCR market. While it seems likely that small market participants are impacted to a greater extent than large ones, this conclusion is based solely on logical deduction.

C. *Production Efficiency.* The CRR market is essentially a financial layer on top of the underlying physical system. The financial layer is not seen as particularly being a *driver* in the physical system. Given the complications associated with obtaining a certain full hedge, it is conceivable that some QSEs may be incented to deviate from fully efficient scheduling and production if doing so allows them to operate in a manner consistent with the hedging instruments they had obtained. To the extent that this occurs, this Change 3 aspect would adversely affect the theoretically achievable benefits of the TNM dispatch efficiency. Based on likelihood and predominance, this is not seen as a big impact.

D. *Promoting Resource Expansion.* The TNM's proposed two-year CRR product offers an incremental degree of stability for expansion. However, both CRRs and TCRs are short term, exposing new resources—even those that make "efficient" siting decisions—to the risk that future resources, future load growth, and future transmission expansion (or lack thereof) will create congestion that cannot be hedged. Thus, Change 3 is seen as a positive yet moderate rather than strong benefit with respect to Resource Expansion.

E. *Grid Expansion.* The impacts of the CRR proposal vs. the Base Case TCR regime with respect to grid expansion are negligible. Decisions to build grid facilities can rarely be justified on the basis of short-term (one or two year) forecasts. Grid planning practices have always considered locational issues, but they use far longer forecasts to estimate the value of proposed facilities. Thus, the planning process would not be materially assisted by the prices of short-term CRRs or short-term TCRs; and the *difference* in value, to a transmission planner, of CRR prices versus TCR prices is likely to be negligible.

F. *Market Power.* Beyond the incentive issue discussed in item C above, it does not seem possible to "exercise market power" per se in the CRR auction process alone. Any CRR-related market power would therefore be limited to the ability to exercise market power in the Balancing Energy or forward energy market or to otherwise schedule in a way that creates an exercise of market power. These issues are discussed as part of the Change 1 and Change 2 Commercial Impacts. Change 3 is not expected to create any different market power impacts.

G. *Grid Reliability.* The proposed CRR-related design changes should not have any significant direct or indirect impacts on grid reliability.

H. *Ability to Conduct Business.* As described earlier, the CRR-related design changes would be expected to have tangible negative impacts on the ability of some grid users (especially smaller ones) to conduct business, because of the relatively greater complexity and because of the shift in risk associated with the change in policies for derations. Finally, there is also the possibility that the commercial risk associated with potential defaults by CRR Obligation-holders could be spread to other entities.

I. *Costs and Administrative Burden.* As described earlier, the cost and administrative burdens for all entities (and especially smaller entities) to participate in the CRR market may be relatively significant, in terms of the need for additional staff, training, and sophistication required to understand the nodal model, to develop CRR bidding strategies, and to manage the use of CRRs. Given that participation in the TCR markets under the Base Case design is somewhat limited, the relative strength of these incremental CRR complexities for QSEs is unknown. ERCOT is expected to have an administrative burden due to the more complex treatment of risk associated with the SFT and the obligation-type CRRs. This is expected to be most significant during the transition period.

Change 4: Pre-assigned Congestion Revenue Rights

Pre-assigned Congestion Revenue Rights (PCRRs) appear to be a rough attempt at a one-for-one replacement of pre-assigned TCRs (PCRs) with pre-assigned CRRs. Both the PCR and the PCRR schemes seem to be attempts to preserve the substance and the value of pre-RTO transmission uses of non-opt-in entities (NOIEs) with the goal of insulating the them from the impacts of congestion pricing.

Because the discount pricing and special features of PCRRs appear to be the results of a negotiated settlement between NOIEs and other ERCOT participants, and because attempting to compare the value of the PCRR proposal to the value of the existing PCRs would require in-depth analysis of each NOIE's transmission uses, the OMIA does not attempt to evaluate the impacts of the PCRR design on the NOIEs.

In the general case, there are several clear results of pre-assigning transmission congestion rights to any entities, rather than assigning them revenue credits (which could be equal to the marginal clearing prices of the transmission congestion rights) and requiring them to acquire the transmission rights in the ERCOT auctions. Doing that reduces the liquidity and price transparency of ERCOT's transmission rights auctions, increases the volatility of the clearing prices for those rights (if enough pre-assigned rights are withheld), increases opportunities for parties to exercise market power, and reduces the ability of other market participants to manage risk. Therefore, from the perspective of facilitating the development of competitive markets, it would be more desirable to pre-assign revenue credits than transmission congestion rights. See, for example, the PJM *2003 State of the Market* report (PJM 2004, p. 32), which documents that the introduction of the allocation of auction rights in 2003 significantly increased liquidity and was seen as removing a barrier to competition.

However, because the OMIA's objective is to compare the PCRR approach with the PCR approach, the key questions become the following:

- Is the quantity of network capacity reserved for PCRRs and PCRs roughly the same? (If so, the NOIEs and the other participants in the marketplace are not significantly impacted one way or another.) Although the answer to this question is not clear from a comparison of the current and proposed ERCOT protocols, the intent of the PCRR proposal makes it appear that the answer is yes. Conversely, if the result is more or less capacity allocated under the TNM, then there would be a value shift between NOIEs and the other participants in one direction or the other.

- Do PCRRs have unique features that render them different, after their pre-assignment, from CRRs? (If so, the liquidity and usefulness of secondary markets for CRRs will be decreased.) For example, some of the PCRRs' proposed features (such as the "refund option") are unique and would therefore prevent that capacity from being available in subsequent auctions. To the extent that such PCRRs are available, the liquidity of the CRRs would be adversely impacted, although the benefit to the NOIEs might be improved.

Commercial Impacts

A. *Facilitation of Competitive Markets.* To the extent that PCRRs are allocated on the refund option and cannot participate in subsequent auctions for reconfiguration, liquidity will be adversely impacted. If quantities of such PCRRs are very small, this impact is probably insignificant. But to the extent that refund type PCRRs constitute a large percentage of grid capacity in certain areas, this impact could be large. To this extent, the TNM would also have a bias toward adversely impacting market participants other than the NOIEs.

B. *Grid Reliability.* There are no substantive differences between the PCRR proposal and the Base Case.

C. *Administrative Burdens.* The refund option seems to create a minor administrative burden on ERCOT with respect to the settlement of the refunded amounts and the tracking of refund and non-refund PCRRs.

D. *Other.* For all other Commercial Impacts of interest in the OMIA: the impacts of CRRs in these areas are already small; and because PCRRs are presumably just a small subset of the capacity that can be allocated to CRRs, the impacts of PCRRs are even smaller and therefore inconsequential.

Change 5: Reliability Unit Commitment

The purpose of the proposed Reliability Unit Commitment (Day-Ahead and Hour-Ahead) functions is to commit resources beyond those committed by market participants when, in ERCOT's judgment, insufficient resources have been committed to reliably operate the grid. RUC would replace the present method for the selection and dispatch of RPRS and is therefore compared with this mechanism in the Base Case.

Replacement Reserve Service was intended both to make up resource balance commitment shortfalls and to provide a mechanism through which to procure capacity for local congestion management. Historically, the RPRS mechanism has not been used, so ERCOT operations staff has modified the RPRS algorithms, which commit units each hour, to incorporate multi-hour considerations. Further, the primary need for capacity services has been for local congestion, where market solutions are not possible. In these cases ERCOT selects the particular unit needed and the unit is paid under OOMC mechanisms. Recent software releases will improve the commitment RPRS algorithms, but they will not resolve the predominant need for non-market local commitment solutions. These non-market local commitment issues and OOM payment policies will likely continue to be problematic.

The TNM with RUC is expected to significantly improve the committing of capacity, because nodal signals should remove any incentives against making otherwise rational self-commitment decisions. Further, EHDAM, with its integrated commitment processes, will couple the optimized energy and commitment decisions, helping to reduce overcommitment or suboptimal commitment. Thus, these market features combined should result in improved commitment outcomes, especially once EHDAM is in place.

With respect to RUC provisions specifically, there does not seem to be any substantial difference between the RUC and RPRS commitment mechanisms. For example:

- RPRS and RUC both occur after the Day-Ahead (DA) scheduling process
- RPRS and RUC are both based on ERCOT-projected loads
- RPRS and RUC both need special provisions to commit out of market

However, the RUC proposal does call for allocation of RUC costs to those QSEs who were short in the forward markets, where allocation quantities could exceed the quantity under-scheduled by the QSE. Such an allocation policy poses the risk of overextending cost-causation principles by penalizing those scheduled short (perhaps inadvertently) for overcommitment on the part of ERCOT. To the extent that such penalties exist, QSEs may overcommit capacity to avoid the penalties. This could lead to an inefficient commitment.

Commercial Impacts

A. *Facilitation of Competitive Markets.* With recent improvements planned for the RPRS market, the impact of the RUC market alone is minimal. However, RUC working with nodal pricing should produce a significantly more efficient outcome than would result under the zonal market with RPRS in the sense of aligning pricing so as to reduce any incentive to overschedule and increase the need for OOM down, for example. Certainly, coupled with the operational improvements of unit-specific bidding, commitment through RUC should be much more transparent than commitment under RPRS/OOMC in the Base Case. However, to the extent that RUC settlement provisions allocate costs beyond cost-causation (for example, in the case of ERCOT over procurement), competitive markets are harmed. The harm is both in the sense of sending misaligned allocation signals to participants and in the sense of the impacts of participants' anticipation of possible charges, including the possible inefficiencies of overcommitment.

B. *Discriminatory Environment.* Given that much of the need for RUC and for RPRS is in the area of local congestion management, it is unclear to what extent improvements through RUC will impact discrimination from a RUC service perspective. The penalty created by over allocating costs to parties that are short may (on a per-MW basis) impact some parties more than others if commitment in some constrained areas is more expensive than in others.

C. *Efficiency of Production.* RUC provisions alone do not seem to impact efficiency relative to the Release 4 improved RPRS. However, when these provisions are coupled with the operational improvements of unit-specific bidding, with nodal pricing, and with commitment through RUC, efficiency should be much higher than efficiency under RPRS/OOMC in the Base Case. The potential allocation of RUC charges based on under commitment may result in an inefficient overcommitment as QSEs try to mitigate that possibility.

D. *Resource and Grid Expansion.* To the extent that nodal prices, coupled with RUC in the TNM design, reduce the current incentives to increase Out-of-Merit Order commitment, RUC will provide much better resource-expansion signals. There appears to be no significant linkage between the RUC design changes and efficient grid expansion.

E. *Market Power.* RUC will not impact the ability to exercise market power, but in conjunction with nodal pricing the TNM may reduce incentives for the exercise of market power in the area of commitment.[116]

F. *Reliability.* Reliability impacts in the near-term should not be significant, given that the grid is operated reliably today. However, to the extent that the Base Case methods are insufficient to ensure the adequacy of on-line capacity, and the economics of that capacity, the proposed design changes may have positive impacts on the margin of grid reliability.

G. *Ability to Conduct Business/Administrative Burdens.* RUC seems no more onerous than the RPRS market. Both will require submission of a relatively limited set of data. Similarly, OOMC and make-whole payments both have the flavor of cost-based settlements, and their burdens on QSEs should be comparable.

Change 6: Modeling Details and Requirements

A nodal pricing market will increase some Market Participants' interest in understanding the detailed ERCOT system and possible pricing outcomes. Section 4.9 of the June 04, 2004 draft of the Texas Nodal Protocols acknowledges that "The ERCOT Market requires accurate modeling of all transmission elements in order to send reasonably accurate pricing signals to Resources participating in the market." Section 4.9.3 of the protocols further states that "ERCOT will make available to TDSPs and all appropriate Market Participants, consistent with applicable policies regarding release of Critical Energy Infrastructure Information, the full transmission model used to manage the reliability of the transmission system as well as proposed models to be implemented at a future date."

It is important that all parties that conduct business under the ERCOT tariff have nondiscriminatory access to all of the information needed to conduct that business efficiently and competitively. Regarding the "full transmission model," it does not seem likely that the term is meant to encompass (1) the software,[117] (2) detailed documentation of the software (including specifications, assumptions, and mathematical algorithms), (3) the "transmission model" and all other supporting data (except for market participants' proprietary data) needed to use the software, and (4) a platform (or access to a platform) on which the software can be used independently by the market participants.

It is likely that ERCOT will simply make available the network model such that third parties can use that underlying topological model in their own simulation tools to try to understand the network model and possible pricing outcomes. (This is in fact the understanding used in the conduct of the IIA.) To the extent that the network model made available is consistent with what is available today, no impacts in this area are expected, although we generally believe that information such as the network model will be more important under the TNM. To the extent that the new protocol language reflects an expectation that additional information will be made available, and to the extent that this comes to fruition, there will be benefits in the area of reduced discrimination because this information will empower smaller market participants and will facilitate the competitive market. There is insufficient information to distinguish the Commercial Impacts further.

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[116] Any second-order effects, such as the impacts on RUC given energy market power or the impact on the energy market power given RUC differences, were not assessed for this analysis.

[117] In this context, "software" includes all code and all documentation for the software that makes decisions that have financial or operational consequences for market participants, including software used for calculating LMPs, for RUC, for ancillary services procurement, for dispatch, and for settlements.

Change 7: Outage Scheduling

The discussion in this section does not pertain, for example, to the manner in which outage scheduling is expected to change between the cases. Rather, it reflects the impact on the same outage scheduling practices with the existence of the TNM.

Under the existing zonal model, users of the grid are to a large extent insulated from the consequences of maintenance outages and associated temporary deratings of grid elements because intra-zonal congestion costs are socialized and because TCRs retain their full value even in the event of physical curtailments or other flow limitations. But with the design changes proposed for the nodal model, every change in a transmission limit—including temporary changes associated with the removal of facilities from service for maintenance (or, for that matter, the unexpected cancellation of an outage)—could cause significant changes in some of the nodal LMPs, creating significant financial consequences for individual QSEs that are injecting or withdrawing energy at those nodes. Further, these financial consequences are not fully hedgeable by CRRs, because CRR payments are derated when transfer capabilities are derated.

Section 4.3.1 of the June 04 2004 Draft Nodal Protocols states that "ERCOT shall approve Planned Outages and accept Maintenance Outages of Transmission Facilities schedules unless, in ERCOT's determination, the requested Transmission Facility Planned Outages or Maintenance Outages of Transmission Facilities would cause ERCOT to violate applicable reliability standards." This language is the same as that in the existing zonal protocols. But in the context of the proposed move to the TNM, ERCOT's limited grounds for rejecting proposed maintenance plans could have significant ramifications for market participants.

The ERCOT documents acknowledge the importance of impartiality in the scheduling of transmission facility maintenance. But Section 4.3.1 indicates that ERCOT would have little ability to prevent nodal pricing manipulation by market participants responsible for maintenance planning, because ERCOT's right to reject proposed maintenance outages is limited to the grounds of violation of reliability standards.

To the extent that the discussion above is accurate, and ERCOT has no ability through other portions of its tariff to rectify this problem, negative commercial consequences could occur in a number of areas. The magnitude of these potential impacts would depend on the details of the roles envisioned for the Transmission and Distribution Service Providers (TDSPs), ERCOT, and other market participants in the maintenance scheduling process and on the transparency of the process itself.

Commercial Impacts

1. *Facilitation of Competitive Markets, Discrimination, and Market Power.* The competitive marketplace is more sensitive to transmission element outages under the TNM. This market feature does not impact the ability to exercise market power, but if that ability exists in the area of outage scheduling, the impacts are likely to be more severe to Competitive Markets and Discrimination under the TNM design.[118] To the extent that adequate assurances protect against such exercise, there is no expected impact in this area.

Change 8: Enhanced Hybrid Day-Ahead Market

When the Cost-Benefit study was conducted, the proposed TNM design included an EHDAM, which would include a combined unit commitment and energy optimization (SCUC/SCED). The EHDAM would be implemented within a year of the start of the TNM market.

The EHDAM offers several functions that are not provided by ERCOT in the Base Case:
- An energy clearing market subject to transmission constraints (be they CSC zonal or full nodal)
- The opportunity for a combined energy and commitment optimization
- The ability to settle CRRs in the Day Ahead

Whereas in many of the Changes we attempt to identify specific attributes of the design change that create incremental individual differences, the EHDAM creates significant challenges in this regard because it is by nature an integrating feature. There is no analogous market feature in the Base Case with which to compare the EHDAM. The ADAM being developed for the current market will offer the ability for participants to conduct trades within the zonal market structure.

The entire package of the EHDAM, nodal pricing, RUC, and unit-specific bidding seems to offer conceptually significant benefits, many of which could not be treated in the EIA. There is a recognition that OOMC payments are significant under today's market design—over $200 million in 2003 (Potomac Economics 2004, p. 21)—and payments for the needed capacity may be greater than would be the case in an efficient market (Potomac Economics 2004, pp. xxiv–xxv, 67–75). Under an LMP-based regime with integrated unit commitment, commitment should be more efficient to the extent that market power, if any, is not exerted. With the TNM, an integrated unit commitment therefore offers increased efficiency in unit commitment. Until the EHDAM is implemented, the commitment process offers some limited opportunity for a more optimal unit commitment, but the EHDAM seems to be the enabler for many of these TNM elements to create benefits.

Suggested benefits are therefore significant. Potential adverse impacts are less tangible, but given that the crux of market designs is usually in the subtleties, they are noted here.

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[118] It is not to suggest that such market power exists or that such market power would be exercised, but just to reflect (as TCA has done elsewhere in the OMIA) any increased sensitivities or vulnerabilities to the exercise of market power.

First, multiple competing marketplaces tend to enhance robustness, customer choice, efficiency, and innovation.[119] ERCOT with EHDAM will be taking the next step to centralized operation by initiating a centralized energy market based on a full network model, complete with unit commitment. While there are expected benefits, operation of such a market does create the possibility that alternative non-ERCOT markets (such as the Intercontinental Exchange, or ICE) will be unable to compete and will become less liquid. While one may argue that it makes no sense to forgo an efficient centralized market in order to provide for alternative markets, ERCOT's operation of such a DA market does unintentionally undermine these alternatives.[120]

EHDAM may similarly create discriminating effects across ERCOT market participants, depending on how it is funded. It would be consistent with "user pays" principles of the costs of developing and administering EHDAM are fully allocated to those who participate in the market. But if there is a market-wide grid or load charge to fund ERCOT's development and administration, then there will be an administrative cost shift for ERCOT market participants generally. This would discriminate against those who otherwise tend to conduct business bilaterally or to use an alternative exchange. It would also create an incentive for market participants to use the ERCOT market instead of their alternative exchanges (or else they end up paying for the service of a market twice, once through the ERCOT uplift and again for the alternative market). This then disadvantages alternative exchanges.

Given that the budgeting details are not included with the protocols, this potential for impact cannot be assessed. It is noted because it is clearly possible.

A second effect relates to the overhead of participating in the market. It is expected that the EHDAM will create new administrative requirements and new needs on part of QSEs in order to conduct business in these markets, and these are expected to be minor relative to overall benefits. This is a voluntary market,[121] so users are free to choose not to use it if the administrative costs are too high. This would tend to affect smaller participants more than larger ones. The predominant impacts are captured in the IIA. However, there are likely to be additional costs of doing business (for example, renegotiating contracts to coincide with EHDAM participation) that may not be captured in the IIA.

Commercial Impacts

A. *Development of Competitive Markets and Discriminatory Environment*. The EHDAM, especially in conjunction with the balance of the TNM provisions, is expected to promote an efficient and more liquid market. Combined with the transparency of the market, this is expected to provide an overall benefit to competitiveness. ERCOT's endorsement and administration[122] of the EHDAM may adversely bias users against alternative markets or exchanges—to a greater or lesser extent, depending upon the cost allocation method. Similarly, the EHDAM cost allocation method may disadvantage non-users if costs are allocated to them.

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[119] Take mail delivery service, for example. With essentially only the U.S. Postal Service providing this service some years ago, there were few choices for customers and little need for the Postal Service to innovate with respect to performance, service options, or price. With the entry into the market of Federal Express, the Postal Service has innovated likely at a faster pace than ever before, and there is pressure for pricing to come down and for service options to increase.

[120] Again, as with other observations in this OMIA, this is not to suggest that the adverse impact is comparable in magnitude to the anticipated benefits.

[121] This assumes that participants are not required to use the market to accomplish some other mechanism such as receiving payment for CRRs.

[122] Depending upon whether ERCOT outsources the market or not.

B. *Production Efficiency.* The EHDAM is expected to offer significant production efficiency given the opportunity for participants' resources to be committed based on centralized information and the energy market details (in addition to participants' current ability to self schedule).[123] Of course these impacts are based on the assumption that the centralized algorithms work efficiently and effectively. There are risks associated with the implementation of such algorithms. It is likely that participants could experience adverse impacts of unintended outcomes of the implementation during the transition period, but that such impacts would be resolved over the long run.

C. *Grid and Resource Expansion.* To the extent that EHDAM reduces reliance on OOM payments for commitment for local congestion, there could be significant siting benefits.[124] The existence of DA nodal energy prices would probably create some improved price signals, but incremental impacts over the real time nodal market are expected to be minor. Incremental impacts on grid expansion are expected to be negligible.

D. *Market Power.* To the extent that EHDAM reduces reliance on OOM payments for commitment, the *impact* of the exercise of market power may be lower. However, the *ability* to exercise market power (based on ownership and system topography) will likely not be impacted by the reduced reliance on OOM payments in the short run.

E. *Grid Reliability.* EHDAM may create more complete and representative visibility for ERCOT Operations regarding expected generation patterns. This, coupled with improved commitment solutions, would probably support reliability, but this effect is seen as modest given that ERCOT is operating the market reliably now.

F. *Ability to conduct business.* The EHDAM is expected to provide another useful method for conducting business in the forward market. To the extent that centralized algorithms can result in aberrant pricing outcomes from time to time (or more likely during the transition period), there would be added risks from participation. Given that the market is optional, it is expected to generally produce net benefits, although to realize those benefits participants may have to tolerate more volatility and uncertainty.

G. *Cost and Administrative Burden.* Participation in a two-market, two-settlement system (DA and RT) will likely create an administrative burden. The burden is seen as small relative to the liquidity and market efficiency benefits, but it is expected to be disproportionately large for smaller QSEs.

6.3 Market Segment and Regional Impacts

This section segregates the impacts presented in Section II into market segments and into regions to the extent relevant. This section does not present any new results, but rather simply tries to "slice" the

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[123] Note that at the time of the production of this OMIA report, discussions were under way to consider including ancillary service optimization in conjunction with the forward DA Market. This would offer even further theoretical potential for optimization.

[124] For example, to remove the incentive for a unit to site to receive OOM Down payments.

results identified in Changes 1 through 8. Especially with respect to the impacts described below, this is a segmentation of the impacts outside of the energy impacts. That is, something characterized as "increased costs due to…" is not net of any potential energy savings, for example. Stated differently, a report of a net increase in cost in this section does not necessarily mean that the segment will incur a net increase in cost under the TNM. To make such a determination, one must consider the impacts associated with the EIA and the IIA in addition to these impacts. Section 7 of the Cost-Benefit Study brings together impacts from all three analyses.

OMIA impacts affect some groups of market participants more than others in a small but significant number of ways.

The discussion in this section is not meant to imply that any of the proposed design changes are unwise or inequitable. Instead its purpose is to point out that those changes may have different consequences for different participants.

Smaller Market Participants

In most of the cases in which OMIA impacts are not distributed proportionately, the disproportionate burdens are related to the *size* of the market participant rather than the previously defined market segments.[125] To the extent that segments are correlated by size, one segment would be impacted more than another. For example, these size impacts probably do not adversely impact IOUs. However, these impacts also would not affect large Independent Power Producers (IPPs) or large marketers, for example. The entities most adversely affected would likely be small independent Retail Energy Providers (IREPs), small municipals and small electric cooperatives, and large end users (similar to how small IREPs are affected, for example).

As noted throughout Section II, many of the OMIA impacts stem from the introduction of new ERCOT and QSE business processes that would result from the proposed nodal resource deployment, nodal settlements, and CRR and EHDAM design changes. These design changes encompass operations planning, scheduling, operations, risk management, CRR management (purchase and sale strategies), settlements, and audits. The new processes are likely to create higher costs, risk-management problems, and the need for additional, sophisticated staff to manage the new complexities. Some of these complexities are unavoidable consequences of the decision to use nodal pricing—they come with the territory. Others, for example in the CRR derating proposals, are consequences of particular design changes.

Small-Portfolio Generators vs. Large-Portfolio Generators

The discussions in Section II with respect to Change 1 yield a distinction in benefits between generators that have large portfolios and those that are small-portfolio or single-resource generators. Change 1 described several outcomes of the Base Case operations related to portfolio bidding for which there may be inefficiency outcomes for the ERCOT system. At the same time, however, the portfolio allows some operational flexibility. Thus, the TNM is likely to afford efficiency benefits to generators who own smaller portfolios and to remove operational flexibility from larger generators

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[125] The pre-defined market segments are (a) Investor-Owned Utilities, (b) Municipal Utilities, (c) Electric Cooperatives, (d) Independent Power Generators, (e) Independent Power Marketers, (f) Independent Retail Electric Providers, and (g) Consumers.

(although they should also benefit from the efficiency gains). Given the relative advantage to larger participants of the use of the portfolio mechanism, the TNM's unit-specific bidding for all would tend to level the playing field.

Qualified Scheduling Entities that Transact Locally

For some QSEs whose business is predominantly "in their own backyards," the OMIA Commercial Impacts described in Section II associated with moving to the proposed nodal model could be disproportionate, given the need to address congestion impacts on their business where no such need exists in the Base Case. For example, for those QSEs whose business is primarily intra-zonal, intra-zonal congestion costs are currently socialized, and tools for hedging intra-zonal congestion risk are unnecessary. However, in the TNM those QSEs will become responsible for local congestion (to the extent that they do not receive PCRRs) and for learning the intricacies of nodal pricing and CRRs.

Recipients of Pre-Assigned Congestion Revenue Rights

Entities that receive PCRRs—primarily municipal utilities and electric cooperatives—would be burdened proportionately less by the switch to nodal markets than would the small QSEs that do not receive PCRRs.

Grid Facility Owners

It is assumed, given the controls that are in place to manage market power and gaming, that any increased propensity for or severity of gaming associated with the transmission system associated with the TNM will not manifest itself as actual impacts.

Users of Congested Facilities

As noted in Section II, those entities that currently use more than a pro rata share of congested facilities (other than CSCs, for which direct responsibility for congestion costs has already been implemented via the zonal model) will see a net increase in costs (to the extent that they are not recipients of PCRRs), because the amount that they pay in nodal congestion rents will exceed their pro rata share of congestion revenue credits. Conversely, those QSEs that under use congested facilities will gain. So to the extent that any of the market segments is more heavily populated with QSEs that fall into one category than the other, that market segment would be more heavily impacted than other market segments.[126]

Summary of Potential Impacts by Segment

This section summarizes segment-specific impacts by those previously identified segments. This discussion is not intended to be comprehensive of all OMIA impacts, but rather summarizes those impacts that have the potential to be segment-specific.

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[126] Note that this is an outcome directly measurable through the EIA. However, though the EIA provides bus-specific prices to perform such an analysis, market participant by market participant impacts are not determined as part of that analysis.

- *IOUs.* IOUs will likely[127] be relatively better equipped to address the complexities of the TNM, especially if the costs associated with addressing them are measured on a per-MWh basis. IOUs may see decreased control in their ability to schedule outages, depending on the controls adopted by ERCOT. Further, IOUs, in losing the operational flexibility of the portfolio bidding and scheduling mechanism, will have to adjust to optimizing the value of their fleet through unit-specific operations.
- *Municipal Utilities.* Certainly to the extent that a particular Municipal Utility is small, the activities and costs associated with the new market characteristics will be higher than average. Further, it is unlikely that Municipal Utilities have any experience with LMP-based markets, as opposed, for example, to a large marketer or IPP. Further, many Munis are likely to mostly transact locally and will thus experience the impacts described in that related section above. Whereas previously there may have been no need for a Muni that is located completely within a zone to have congestion management capabilities, such participants will now be impacted by congestion costs and will need to address risk management strategies even if they are eligible for PCRRs. (To the extent that a Muni can obtain PCRRs, however, that Muni may be less affected by the TNM congestion impacts than other QSEs that do not obtain PCRRs.)
- *Electric Cooperatives.* Small electric cooperatives will be adversely affected by the complexities described in the Smaller Market Participant section. Additionally, some electric cooperatives may fall into the category of those that use a disproportionate fraction of the transmission grid—if their transactions span the ERCOT system. However, most of the effects of such a portfolio are presented in the EIA segment analysis and therefore need not be revisited in this OMIA.
- *Independent Power Producers* (IPPs). To the extent that IPPs are small they will be adversely affected by the complexities of the TNM. IPPs that operate outside of Texas may already have experience with nodal markets and so may be better able to address these complexities. IPPs will see an increased impact of congestion costs given their necessarily increased use of the local constraints and the direct allocation of these costs in the LMPs, as opposed to the uplift of the intra-zonal costs by load share (via QSEs). Certainly IPPs will not receive PCRRs, nor will they have the advantages IOUs may have through participation in transmission line outage scheduling. To the extent that they have smaller portfolios, IPPs are expected to experience the relative benefits described in the small versus large portfolio topic above (page 6-39).
- *Marketers.* Though the Marketer segment is not specifically defined, it is assumed that marketers' business generally crosses ERCOT zonal boundaries today and that Marketers generally have a higher level of knowledge of LMP markets through their activities in other markets. Given this, the various types of complexity are unlikely to adversely affect marketers. Rather it is expected that the Marketer Segment will benefit from increased efficiency, transparency, and liquidity. The change in risk related to CRRs relative to TCRs may be an adverse impact in that marketers that do not have a REP role will see the shift of risk from the loads to them. Given the expected level of sophistication of marketers participating in the CRR auction, however, it is likely that this impact will be mitigated by the marketer simply adjusting the price they are willing to pay for the rights.
- *Independent Retail Energy Providers.* Small IREPs will experience the impacts of the new market processes, which will be less significant after the transition period. IREPs do not receive PCRRs and so realize none of their potential advantages. Energy and congestion

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[127] As the size of an IOU decreases, it will begin to look more like a "Smaller Market Participant" than an "IOU" per se.

impacts, more the subject of the EIA, will depend on the nature of the customer portfolio.[128] An IREP may be adversely impacted to the extent that it has supply separate from its load and is accountable for the transmission costs of delivery to the load. IREPs that have "seller's choice" contracts may be especially adversely impacted by a transition to a nodal market.

- *Consumers.* The largest impact to Consumers is the bulk cost of electricity, and this impact is addressed in the EIA. However, some consumer segments may experience impacts comparable to those experienced by some of the other market segments addressed in this section. For example, large end users may be at risk (mostly during the transition period) for the impacts of adapting to the TNM business practices and for the impacts of the congestion cost shift. They will rely on their REP or their QSE to manage their CRR processes and/or they will be faced with addressing the complexities of CRRs on their own. Similarly, large end users that hold contracts for energy deliveries may have to address the impacts of delivery points different from their load nodes or may be required to negotiate new delivery terms. In short, large end users may see all the various impacts and yet not be of a size to manage these impacts themselves.

Regional Issues

The essential regional driver described here is the same driver quantified in the EIA, that is, energy costs. It is described here for completeness.

The primary regional impact associated with the proposed design changes stems from the shift from zonal pricing to nodal pricing. Under the zonal model, local (i.e., non-CSC) congestion costs are rolled up ERCOT-wide and allocated ERCOT-wide on a load ratio share basis. The end result is that loads in less-congested areas generally subsidize the congestion-related costs of loads in more-congested areas.

Under the nodal model, these subsidies do not disappear, but they take a different form. Nodal congestion rents (together with CRR auction revenues and payments to CRR holders, which in theory should net to a small positive amount reflecting the value of the CRR risk premium) are rolled up ERCOT-wide and allocated ERCOT-wide on a load ratio share basis. The end result is that loads in less-congested areas will be net beneficiaries of payments from loads in more-congested areas.

Redistributions of congestion rents between loads within zones are minimized under the nodal model, because loads within a zone would pay the weighted average of the nodal prices in the zone. But between zones, the proposed design would move congestion rents from more heavily congested zones to less heavily congested zones.

Whether or not this redistribution is equitable is not an OMIA issue. However, it should be noted that to the extent that responsibility for the cost of transmission grid upgrades is also allocated to loads on an ERCOT-wide basis, the ERCOT-wide redistribution of congestion rents just described would appear to be economically consistent.

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[128] Note that the EIA provides segment analysis for the congestion and energy cost impacts. However, it does so for the entire customer class, not providing direct results for any one IREP.

6.4 Alternative Cases

The OMIA-related impacts of the two alternative cases, the Replication Change Case and the Nodal Light Change Case, are discussed in this section. The impacts are presented in terms of their differences from those of the TNM case.

These two alternative models are under consideration because they do not vary too significantly from the TNM and because their implementation might result in some cost savings (for the Replication case, in the area of software implementation; for the Nodal Light case, in the areas of telemetry, metering, settlements, and billing). The extent to which there may be savings in these areas is discussed in the IIA.

Replication Change Case—Incremental Impacts

Briefly, the Replication Change Case (RCC) assumes that instead of the TNM, a commercial model similar to that of ISO-NE, with appropriate RTO software, would be implemented, with only minor changes made to incorporate a few specific differences such as the use of average losses rather than marginal losses. There are myriad smaller differences in such areas as modeling requirements, scheduling time frames, ancillary services definitions, requirements and deployment, but these differences are expected to have an insignificant effect on the Commercial Impacts.

The most significant short-run difference between the two models, from the standpoint of market participants, is that the ISO-NE day-ahead market is an integrated energy and commitment market in which scheduling and dispatch are driven by SCUC and SCED algorithms.[129] Given the strict definition of the RCC, it was assumed for the sake of this OMIA that this would result in a day-one forward energy and commitment process. Thus, the benefits of such a forward market (as reflected under the EHDAM change discussion in Section II) would be experienced on day one (the start of the TNM). However, the algorithmic risks and the added administrative efforts and their costs would also be experienced on day one. On net, while combining real-time market changes with the introduction of a day-ahead optimized market at the same time might create greater impacts of change management, there is also the possibility of market participant implementation efficiencies. It is not clear how these would net. Certainly the other anticipated benefits of the forward market would be recognized sooner under this scenario.

Further, one very strong distinguishing feature of the RCC is that it would employ tested algorithms and data management systems. This should significantly reduce the risks of the unknowns, limiting them primarily to boundary issues (integration with other ERCOT systems and with the ERCOT network model).[130] This is expected to be a significant benefit and one that is linked especially to the selection of the ISO-NE system, which seems to have been free of market system anomalies. For example, ISO-NE reports that the volume of price corrections—which usually indicate implementation problems or software flaws, operations or data errors, system failures, and communication errors—has remained low throughout ISO-NE's transition to a nodal market. Price corrections in the ISO-NE during the first six months of operations occurred in less than one percent of the five-minute intervals. The ISO-NE attributes these results to the extensive development resources devoted to the market implementation and the extensive systems testing (Patton, Lee-Van Schaick, and Sinclair 2004, pp. 32–33).

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[129] Two other differences of interest are that the ISO-NE market makes use of Installed Capacity requirements and marginal transmission losses. It is assumed here that these two features of the ISO-NE software would be disabled for use in ERCOT.

[130] There are other potential complexities of implementing the Replication Case software with existing ERCOT systems, such as the Market Operations System and Load Star, as well as the Utility Commission's market monitoring software. These are assumed to be captured by the implementation costs included in the IIA.

There are a number of differences between the RCC and the TNM with respect to congestion rights. The ISO-NE congestion rights model differs from that of the TNM in that there are no PTP Options CRRs, only PTP Obligations CRRs, and there are no special provisions for PCRRs,[131] including real-time scheduling or refund options. Thus, current PCR holders' terms for congestion rights would be significantly diminished with RCC in the current form of the ISO-NE. Note, however, that if the RCC was implemented in its current form, such that all CRRs were settled in the day-ahead, several issues and questions regarding the impact of the option of real-time settlement would be resolved. Thus, there are positive and negative impacts from this difference, but the negative impacts clearly would affect the particular NOIE segment through the loss of the PCR characteristics. The ISO-NE market currently has only annual and monthly auctions, and no two-year auction as proposed for the TNM. This is seen as a disadvantage toward market participant's having long-term hedges. However, it is also likely that a two-year auction is not a severe limitation (if it is a limitation at all) of the software systems, and can therefore be configured.

Nodal Light Change Case Incremental Impacts

In the Nodal Light model, nodes at which there are no resources would be eliminated from the commercial model by aggregating them into a small number of equivalent nodes, significantly reducing the number of nodal pricing locations. (In addition, individual units would be aggregated to a plant or resource level.) Because energy withdrawals are charged at a zonal price in the TNM, there is no immediate commercial need for nodal prices at non-injection nodes. However, as dispatchable demand is integrated throughout the grid, the Nodal Light model would have to evolve into a full nodal model, though there is no indication that this is occurring at a significant pace.

It was assumed for this OMIA that the Nodal Light case would make use of the same operations model as the TNM. (Whereas there may be a more simplified settlements model, the SFT and optimal dispatch would need to monitor the full network.) At the conceptual level, there would be no significant differences between the two models. However, since resource-specific scheduling and bidding would be used instead of portfolio-level scheduling and bidding the Nodal Light Change Case may not resolve all of the operational issues. For example, the issue of a combined ramp could continue to be problematic (e.g., if there is a gas turbine and a combined cycle plant at the same location). Although resource-specific scheduling may be less voluminous than scheduling at the unit level, scheduling at this level would be problematic if the units do not have the same characteristics.

Making use of the same operational model presents similar complexities (comparable to what was described in Section II): the need for release of the model, and the resulting differentiation between large, sophisticated market participants and smaller market participants. Further, new types of complexities are likely to arise as a result of the need to keep the simplified database model up to date, in addition to ERCOT's need to keep the underlying physical nodal representation current. And any savings associated with using existing ERCOT systems will be coupled with the complexities and risks associated with modifying them, for example to implement resource-specific bidding and procurement of ancillary services.

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[131] Note that ISO-NE does not have auctions for special rights such as PCRRs. It is assumed that the provision of PCRRs could be accomplished with the ISO-NE case.

There would be little change in the CRR model, which in the TNM is already a resource node-to-zone (or hub) model.

Given that there is little change in the areas listed above, little downstream change would be expected in the areas of efficiency of resource expansion or grid expansion.

The environment in which market participants operate would be arguably simpler (in terms of reduced dimensionality, but not in complexity of concepts or processes), possibly resulting in lower costs of conducting business processes in the areas of billing and settlements. This is subject to the caveats in the next paragraph, however.

The above is based on the assumption that whenever Load Resources (e.g., LARS, dispatchable demand) and distributed generation materialize at a physical bus, that bus would become an explicitly represented node in the commercial pricing model as well. Otherwise, the growth of dispatchable demand and distributed generation would be thwarted, because such resources would not receive the nodal prices that may be key drivers of the growth of these technologies. (Instead of the node-specific price, they would receive a lower, weighted-average price derived for an aggregated group of nodes.)

If the assumption is correct that the pricing model would be updated as Load Resources and distributed generation materialize, then some of the benefits of simplified billing and settlements would diminish, because market participants would need to accommodate a constantly changing commercial/pricing model.

On the other hand, if the pricing model was not updated with new nodes as Load Resources and distributed generation materialized, then the growth of these resources would probably be hindered, with significant negative consequences for efficiency of production, efficient resource and grid expansion, reduction in opportunities to exercise market power, and growth of competitive markets.

Summary of Alternative Change Case Impacts

Table 4 presents a summary of the identified incremental[132] impacts of the Replication Change Case and the Nodal Light Change Case.

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[132] Incremental to the TNM Change Case.

Table 6-3— Summary of OMIA Impacts of Change Cases Relative to Texas Nodal Model

Commercial Impact	Replication Case	Nodal Light Case
1. [Facilitate Development of] **Competitive Markets**	Significant risk of market engine anomalies. More likely short run increase in trading liquidity given integrated market day-one.	Possibly less burdensome settlements (lower dimensionality of model); but depending on how Load Resources and distributed generation are handled, new entrants might be thwarted.
2. [Minimize] **Discriminatory Environment**	Comparable level of complexity as implementation of EHDAM. Shift in NOIE PCRR terms	Possibly reduces back-office impacts to small market participants; not believed to be significant given total of all requirements.
3. [Increase] **Efficiency of Production**	Day-one benefits given availability of co-optimized commitment and dispatch process.	Depending on how Load Resources and distributed generation are handled, either: (a) insignificant; or (b) strong negative; potential adverse impact to the extent that different unit types are located at the same resource node.
4. [Promote] **Efficient Resource Expansion**	Not significant	Depending on how Load Resources and distributed generation are handled, either: (a) insignificant; or (b) strong negative
5. [Promote] **Efficient Grid Expansion**	Not significant	Depending on how Load Resources and distributed generation are handled, either: (a) insignificant; or (b) strong negative
6. [Reduce] **Opportunities to Exercise Market Power**	Not significant	Depending on how Load Resources and distributed generation are handled, either: (a) insignificant; or (b) strong negative
7. [Enhance] **Grid Reliability**	Not significant	Not significant
8. [Facilitate] **Ability to Conduct Business**	To the extent that the RCC would result in fewer market price recalculations, the ability to conduct business would increase.	Possibly less burdensome due to lower dimensionality of the pricing model. But possibly more burdensome if the model changes frequently. Also possibly significant hindrance to the growth of Load Resources and distributed generation if the pricing model is not updated to accommodate new entrants
9. [Minimize] **Costs and Administrative Burdens**	To the extent that the RCC would result in fewer market price recalculations, cost and administrative budget would be lower	Possibly less burdensome due to lower dimensionality of the pricing model. But possibly more burdensome if the model changes frequently

OMIA Conclusion

This report presented the ERCOT Cost-Benefit Study Other Market Impact Analysis (OMIA), including the approach and the results. It was intended to address impacts other than those included in the energy modeling aspects of the Cost-Benefit Study (the EIA) and the Implementation Impact Analysis of that study (the IIA). The analysis investigated several critical TNM Significant Design Changes and measured the impacts of each change against a series of Commercial Impacts. The OMIA is qualitative in nature.

Section II makes a number of impacts evident.

The most substantial positive impacts are the following:

- The decrease in operational challenges for ERCOT associated with using portfolio information from market participants;
- The increased efficiency (beyond what is measured in the EIA) arising from the use of improved dispatch given unit-specific information rather than ERCOT-estimated information from the portfolios and from the combined capacity and energy optimization offered by EHDAM;
- The increased price discovery for specific locations made available with the TNM.

The most substantial adverse impacts are the following:

- The added complexity of the centralized, nodal market;
- A potential for risk shifts to users of the grid (in addition to the cost shifts identified in the EIA) both in terms of the CRRs that derate in the TNM and in terms of the increased congestion costs and the increased financial volumes that will likely be processed through ERCOT's systems;
- The algorithm and implementation risks associated with the TNM, such as those that have shown up in other markets where price re-runs occur;
- Other unanticipated risks of implementation of the new market structure.

The most significant adverse segment impacts affect relatively small market participants, because many of those impacts are associated with increased complexity. There are additional identified impacts that affect one *class* of participants more than others. The *classes* cannot be uniquely mapped to the particular *segments*, however. For example, users who use the transmission grid within a zone to a much greater extent than others are likely to experience more cost and risk impacts. Yet participants with those characteristics would probably be from several different segments.

While the RCC is expected to have both positive and negative impacts, it is that the RCC is based on the ISO-NE system that provides the strongest expected benefits. This is because the ISO-NE market has a demonstrated record of few flaws and smooth and accurate operations. Given this, the RCC seems to offer a significant decrease in risk related to the market engine, provided that the software boundary issues are managed rigorously. The ISO-NE design suggests that the RCC may limit features of PCRRs anticipated in the TNM, which would adversely impact the position of NOIEs if the value of such features could not provided through exercising the RCC systems or through other policies. Note that while the relative magnitude of this adverse impact may be less than the benefits of the reduced risk, the impact would be concentrated with one market segment.

The Nodal-Light change case offers a reduced number of settlement points yet raises two possible adverse impacts: (1) that as LaaRs become more prevalent the Nodal-Light structure will not support their proper settlement, and (2) that there may continue to be operation issues and accompanying inefficiencies if there are generation nodes with two different types of units and if these units must be represented with a single set of characteristics.

OMIA References

The documents below are cited in the body of the OMIA or were otherwise reviewed in the conduct of the OMIA. These documents can be found on the ERCOT web site at <http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=76&b=>.

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7 Comprehensive Study Regional and Segment Impacts

This section summarizes study-wide impacts to regions and segments. It relies upon the results presented in Section 3, the EIA; Section 5, the IIA; and Section 6, the OMIA. Regions and Segments are discussed in that order.

Summary of Regional Impacts:

Regional Impacts were only evaluated based on the EIA. As a result, this Section 7 regional summary is no different than the regional summary of Section 3.3.2.6.1 which contains the detailed numerical results for generation impacts, and Section 3.3.2.6.2, which contains the detailed impacts to loads by region. Impacts to each region are summarized here.

- Houston Zone

  Generators in the Houston Zone experience the greatest decrease in net revenues associated with the Change Case, representing 90% of the ERCOT total decrease in net revenues. In the near term (2005–2008), the impact on generators in Houston is largely driven by the significant decline in market prices in Houston anticipated with the introduction of the nodal market. For example, the Houston zonal price in 2005 is estimated at $45.8/MWh on average over all hours. For comparison, the average of all LMPs in the Houston Zone in 2005 (over all hours) is estimated at $40.4/MWh.

  This decline in prices in the Houston Zone is driven by better *inter*-zonal congestion management achieved under the Change Case scenario when deployment of generating units required to resolve inter-zonal congestion is based on actual, not average, shift factors. As a result, a different dispatch of generating units in the Houston Zone under the Change Case scenario allows the resolution of the congestion on the South-Houston CSC and the reduction of prices in the Houston Zone. With lower prices under the Change Case scenario, generation in Houston will decline with respect to the Base Case scenario. In sum, generators in Houston will see lower net revenues. This trend will continue over the mid-term and mostly in the long-term, although over that period it is influenced not only by prices but also by big differences in capacity additions between scenarios.

  Loads in the Houston Zone pay less to serve load with nodal in all years.

- North Zone

  Generators experience a decline in net revenues in the North Zone, largely driven by anticipated decline in nodal prices *to generators* in the north that will be lower than the zonal price under the Base Case. (It is important to note that at the same time average nodal price *to loads* in the North Zone will likely be higher than the zonal price, reflecting significant congestion within the North Zone).

  Loads in the North Zone pay less to serve load with nodal in all years.

- Northeast Zone

  Prices in the Northeast Zone will increase with the Change Case, reflecting higher generation in the Northeast Zone due to the ability to export more power to the North. As a result, net revenues to generators in the Northeast Zone will increase in all years except 2005.[133]

  Loads in the Northeast Zone pay less to serve load with nodal in all years when congestion rent refunds are considered (and all but 2014 when they are not considered).

- South Zone

  In the near term (2005–2008), the impact on generators in the South Zone is largely driven by the significant decline in market prices in the Houston Zone anticipated with the introduction of the nodal market and by a much smaller price increase in the South Zone. Generators in the South Zone see an increase in net margins. A different dispatch of generating units in the Houston and South Zones under the Change Case scenario allows the resolution of the congestion on the South-Houston CSC and the reduction of prices in the Houston Zone and an increase in prices in the South Zone. In the South Zone, generation will increase. In sum, generators in the South Zone will see higher revenues. This trend will continue over the mid-term and mostly in the long-term, although over that period it is influenced not only by prices but also by big differences in capacity additions between scenarios.

  Loads in the South Zone pay higher costs in the near-term but pay lower costs under the nodal market in the mid- and long-terms. The major reason behind that switch in the impact on loads in the South Zone is the difference in the capacity expansion strategies under the two scenarios. Under the Base Case, new capacity is added in the Houston Zone in 2009 and 2010, whereas under the Change Case, new capacity addition in these two years takes place in the South Zone. As a result, under the Change Scenario during 2009–2010 prices in the South Zone decrease and fall below zonal prices under the Base Case scenario. This reversal in price relationship between the two scenarios is the major driver behind the impact on loads in the South Zone.

- West Zone

  Under the Change Case, net revenues to generators in the West Zone decline along with the decline of generation and prices. With improved congestion management under the Change Case scenario, the generation in the North Zone becomes more competitive: more expensive generators in the North Zone are displaced by importing less expensive generation from the Northeast Zone; that, in turn, reduces the need for imports from the West Zone to the North Zone, and depresses prices and drives down revenues to generators in the West Zone.

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[133] In 2005, simulation results show almost no increase in generation and therefore export from Northeast to North. It is likely that the increase in the export capability becomes possible with new transmission upgrades effective only in 2006.

Loads in the West Zone pay less to serve load with nodal in all years when congestion rent refunds are considered.

Summary of Segment Impacts:

This section presents the results as they pertain to particular market segments. Segments specifically addressed in one or more portions of the study are the following:

- Investor-Owned Utilities (IOUs)
- Municipal Utilities (Munis)
- Electric Cooperatives (COOPs)
- Independent Power Generators or Producers (IPPs)
- Independent Power Marketers (IPMs)
- Independent Retail Electric Providers (IREPs)
- Affiliated Retail Electric Providers (AREPs)

Note that with respect to the Consumer Segment, the overall impacts of the study are seen as indicative of the sum of the net of impacts to consumers. TCA/KEMA had no particular guidance in the study regarding assumptions on how the wholesale price impacts would ultimately impact consumers through (for example) retail ratemaking policies. As a result, no other specific consumer impacts have been identified.

Also note that the implementation impacts referred to herein are based on the average impacts assessed for the TNM design for the particular segments. However, the largest implementation impact accrues to ERCOT at between $60 and $76 million NPV, and this cost will likely accrue to various segments through an uplift mechanism. Further, a small fraction of total implementation costs ($3 to $6 million) could not be assigned to any particular segment during the conduct of the IIA. See Section 5 for more IIA details.

The specific segment impacts determined are discussed below.

- Investor-Owned Utilities (IOUs) and Affiliated Retail Energy Providers (AREPs)

IOU generation results follow the average market trend, with a generation net margin reduction ($1.6/MWh on average) over the study horizon. Overall, the IOU generation net margin decreases by $204 per year on average or $1.68 billion NPV over the study horizon.

AREP load is spread fairly evening across ERCOT, such that the results follow average market trends. AREP load on average benefits by an average of $3/MWh, more or less an average of the impacts across the zones. This results in a net impact of a $462 million annual decrease in the cost to serve load on average, or $3.6 billion NPV over the study horizon.

Implementation impacts for IOUs are expected to be approximately –$13 million NPV.

Based on the OMIA, IOUs will likely be relatively better equipped to address the complexities of the TNM, especially if the costs associated with addressing them are measured on a per-MWh basis. IOUs may see decreased control in their ability to schedule outages, depending on the controls adopted by ERCOT. Further, IOUs, in losing the operational flexibility of the portfolio bidding and scheduling mechanism, will have to adjust to optimizing the value of their fleet through unit-specific operations.

Table 7-1 contains the summary a segment-specific impacts to IOUs.

Table 7-1 Segment-Specific IOU Impacts

	Annual Average from EIA ($M)	NPV ($M)
EIA Load Impacts - Net reduction in cost	462	3597
EIA Generation Impacts - Net impact on revenues	–204	–1679
Implementation Impacts	N/A	–13
Other Market Impacts	Can better adapt to complexities; Decreased control in scheduling outages; Have to adjust to optimizing based on unit-specific representations	

- Municipal Utilities (Munis)

Munis' generation margin is higher in the near-term with the Nodal Case. This follows the regional trend in the South Zone, where most of their generation and loads are concentrated. Overall, the Muni generation net margin increases by $14 million per year on average, or $129 million NPV over the study horizon.

The Muni load impact is primarily driven by geography. Munis serve loads mostly in the South Zone. Some 89% of the load served by Munis is in the South Zone, where the cost to serve load increases in the near-term under the Nodal Case**.** Muni presence is minimal in the North Zone and zero in the Houston Zone. This results in a net impact of a $26 million annual decrease in the cost to serve load on average, or $98 million NPV over the study horizon.

Implementation impacts for Munis are expected to be approximately –$11 million NPV.

Based on the OMIA, and certainly to the extent that a particular Muni is small, the activities and costs associated with the new market characteristics will be higher than average. Further, it is unlikely that Munis have any experience with LMP-based markets, as opposed, for example, to a large marketer or IPP. Further, many Munis are likely to mostly transact locally and will thus experience the impacts related to QSEs Who Transact Locally in Section 6. Whereas previously there may have been no need for a Muni that is located completely within a zone to have congestion management capabilities, such participants will now be impacted by congestion costs and will need to address risk management strategies even if they are eligible for PCRRs. (To the extent that a Muni can obtain PCRRs, however, that Muni may be less affected by the TNM congestion impacts than other QSEs that do not obtain PCRRs.)

Table 7-2 contains the summary a segment-specific impacts to Munis.

Table 7-2 Segment-Specific Muni Impacts

	Annual Average from EIA ($M)	NPV ($M)
EIA Load Impacts - Net reduction in cost	26	98
EIA Generation Impacts - Net impact on revenues	14	129
Implementation Impacts	N/A	–11
Other Market Impacts	Likely disproportionately high costs to respond to new market design; Little embedded experience with other nodal markets; New need to hedge congestion relative to past operations within single zone.	

- Electric Cooperatives (COOPs)

The COOPs' generation margin is lower in the near-term (2005 and 2006) with nodal. However, that trend reverses in 2007–2008, and is lower again with nodal in 2009 and beyond. This is due to the interplay of geography and the new entry trends. Overall, the COOPs generation net margin decreases by $14 per year on average, or $129 million NPV over the study horizon.

The COOP impact is primarily driven by geography. COOPs serve loads mostly in the South and West Zones. Some 75% of the load served by COOPs is in the South and West Zones, where the cost to serve load increases in the near-term under the Nodal Case. COOP presence is minimal in the North Zone and zero in the Houston Zone. This results in a net impact of a $23 million annual decrease in the cost to serve load on average, or $138 million NPV over the study horizon.

Implementation impacts for COOPs are expected to be approximately –$11 million NPV.

Based on the OMIA, small electric cooperatives will be adversely affected by the complexities described in the Smaller Market Participant section. Additionally, some electric cooperatives may fall into the category of those that use a disproportionate fraction of the transmission grid—if their transactions span the ERCOT system.

Table 7-3 summarizes the segment-specific impacts to COOPs.

Table 7-3 Segment-Specific COOP Impacts

	Annual Average from EIA ($M)	NPV ($M)
EIA Load Impacts - Net reduction in cost	23	138
EIA Generation Impacts - Net impact on revenues	–14	–105
Implementation Impacts	N/A	–11
Other Market Impacts	Likely disproportionately high costs to respond to new market design; Little embedded experience with other nodal markets; May have higher proportionate new use of grid.	

- Independent Power Generators or Producers (IPPs)

IPPs' generation results follow the average market trend. However, IPP generators see the greatest net revenue reduction with nodal ($2.4/MWh) on average. Overall, the IPP generation net margin decreases by $304 million per year on average or $2.38 billion NPV over the study horizon.

Based on the OMIA, to the extent that IPPs are small they will be adversely affected by the complexities of the TNM. IPPs that operate outside of Texas may already have experience with nodal markets and so may be better able to address these complexities. IPPs will see an increased impact of congestion costs given their necessarily increased use of the local constraints and the direct allocation of these costs in the LMPs, as opposed to the uplift of the intra-zonal costs by load share (via QSEs). Certainly IPPs will not receive PCRRs, nor will they have the advantages IOUs may have through participation in transmission line outage scheduling. To the extent that they have smaller portfolios, IPPs are expected to experience the relative benefits described in the small versus large portfolio discussion in Section 6.

Implementation impacts for IPPs are expected to be approximately –$13 million NPV.

Table 7-4 summarizes the segment-specific impacts to IPPs.

Table 7-4 Segment-Specific IPP Impacts

	Annual Average from EIA ($M)	NPV ($M)
EIA Load Impacts - Net reduction in cost	N/A	N/A
EIA Generation Impacts - Net impact on revenues	–304	–2378
Implementation Impacts	N/A	–13
Other Market Impacts	Disproportionate impact of complexities for small IPPs without business in other nodal markets; Relative benefit due to elimination of portfolio bidding.	

- Independent Power Marketers (IPMs)

  Given that the IPM business in the energy market is not specifically captured, and that it changes over time and with the implementation of new market rules, no energy impacts were captured for the IPMs in the EIA.

  Based on the OMIA, though the IPM segment is not specifically defined, it is assumed that marketers' business generally crosses ERCOT zonal boundaries today and that IPMs generally have a higher level of knowledge of LMP markets through their activities in other markets. Given this, the various types of complexity are unlikely to adversely affect marketers. Rather it is expected that the IPM Segment will benefit from increased efficiency, transparency, and liquidity. The change in risk related to CRRs relative to TCRs may be an adverse impact in that marketers that do not have a Retail Energy Provider role will see the shift of risk from the loads to them. Given the expected level of sophistication of marketers participating in the CRR auction, however, it is likely that this impact will be mitigated by the marketer simply adjusting the price they are willing to pay for the rights.

Implementation impacts for IPMs are expected to be approximately –$9 million NPV.

Table 7-5 summarizes the segment-specific impacts to IPMs.

Table 7-5 Segment-Specific IPM Impacts

	Annual Average from EIA ($M)	NPV ($M)
EIA Load Impacts - Net reduction in cost	N/A	N/A
EIA Generation Impacts - Net impact on revenues	N/A	N/A
Implementation Impacts	N/A	–9
Other Market Impacts	Given likely experience in other nodal markets, expected lower impact of complexities; Benefits due to increased efficiency, transparency, and liquidity; Adverse risk shift given potential deration of CRRs.	

- Independent Retail Electric Providers (IREPs)

IREP load is spread fairly evening across ERCOT, such that the results follow average market trends. IREP load on average benefits by an average of $2.4/MWh, more or less an average of the impacts across the zones. The IREP segment has no generation impacts. This results in a net impact of a $314 million annual decrease in the cost to serve load on average, or $2.48 billion NPV over the study horizon.

Implementation impacts for IREPs are expected to be approximately –$2 million NPV.

Based on the OMIA, small IREPs will experience the impacts of the new market processes, which will be less significant after the transition period. IREPs do not receive PCRRs and so realize none of their potential advantages. Energy and congestion impacts, more the subject of the EIA, will depend on the nature of the customer portfolio.[134] An IREP may be adversely impacted to the extent that it has supply separate from its load and is accountable for the transmission costs of delivery to the load. IREPs that have "seller's choice" contracts may be especially adversely impacted by a transition to a nodal market.

Table 7-6 summarizes the segment-specific impacts to IREPs.

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[134] Note that the EIA provides segment analysis for the congestion and energy cost impacts. However, it does so for the entire customer class, not providing direct results for any one IREP.

Table 7-6 Segment-Specific IREP Impacts

	Annual Average from EIA ($M)	NPV ($M)
EIA Load Impacts - Net reduction in cost	314	2485
EIA Generation Impacts - Net impact on revenues	N/A	N/A
Implementation Impacts	N/A	–2
Other Market Impacts	Small IREPs will see disproportionate impacts of complexities.	